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NEWFOUNDLAND
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Conference Proceedings

"Offshore Newfoundland in the 1990s: An Assessment of the Economic Environment"

St. John's, Newfoundland
June 4–6, 1990

NOIA
Conference '90

◆

St. John's, Newfoundland
June 4–6, 1990

Offshore Newfoundland in the 1990s: An Assessment of the Economic Environment

◆

6th International Offshore
Petroleum Conference

NEWFOUNDLAND OCEAN INDUSTRIES ASSOCIATION

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A MESSAGE FROM THE CHAIRMAN

The Newfoundland Ocean Industries Association (NOIA) was proud to host its 6th International Petroleum Conference (NOIA Conference '90) concurrent with the Offshore Newfoundland Petroleum Exhibition.

The theme "Offshore Newfoundland in the 1990s: An Assessment of the Economic Environment" had been selected to place in perspective the economic factors affecting petroleum development potential offshore Newfoundland during the next decade.

An excellent balance of private and public speakers covering the full spectrum of session topics was received in response to the conference's Call for Papers.

Speakers from western Canada, Newfoundland and the North Sea gave presentations which lead to very stimulating panel discussions each day. This interaction between the panel and the audience enhanced the value of the sessions and was well received by the NOIA membership. The NOIA Board of Directors extends appreciation and thanks to each of the speakers for their participation in this conference.

I would also like to thank the members of the Conference Committee (Eric Gray, Bruce Colbourne, John Henley and Ruth Graham) for their assistance and support in organizing this year's conference. In addition, the smooth administration of the program is attributable to NOIA's Executive Director Ruth Graham, with the assistance of Pam Walter and Cathy Breen.

NOIA also gratefully acknowledges the Atlantic Canada Opportunities Agency (ACOA) and the Department of Development, Government of Newfoundland and Labrador for their continued support.

Brian Jonasson

Brian Jonasson
Chairman Conference Committee

CONFERENCE COMMITTEE

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Canada-Newfoundland Offshore Petroleum Board

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NOIA Director
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PROGRAM

7:45 - 8:15	Registration
8:15 - 8:30	Official Opening The Honourable Rex Gibbons Minister of Mines and Energy Government of Newfoundland and Labrador

SESSION I - WORLD ENERGY TRENDS

8:30 - 9:10	**WORLD OIL MARKET PROJECTIONS: 1990 - 2005** Anthony E. Reinsch Canadian Energy Research Institute CANADA
9:10 - 9:50	**OIL SUPPLY AND DEMAND AND PRICING ISSUES** Cyril Sturge Department of Mines and Energy Government of Newfoundland & Labrador CANADA
9:50 - 10:30	**IMPROVED PROSPECTS FOR OIL IN THE 1990s** Patricia Mohr The Bank of Nova Scotia CANADA
10:30 - 11:00	COFFEE BREAK
11:00 - 11:40	**THE EFFECTS OF OIL PRICE, INFLATION, INTEREST RATES AND CURRENCY EXCHANGE RATES ON OFFSHORE PROJECT VIABILITY** Barry Rodgers Department of Mines & Energy Government of Newfoundland & Labrador CANADA
11:40 - 12:20	**THE IMPACT OF GOVERNMENTS' INDUSTRIAL BENEFITS POLICIES ON OFFSHORE PETROLEUM DEVELOPMENTS** Clyde Granter Department of Development Government of Newfoundland & Labrador CANADA
12:20 - 12:50	Panel Discussion with the Day's Speakers Moderator: Brian Jonasson Canada-Newfoundland Offshore Petroleum Board

SESSION II - REGULATORY AND ENVIRONMENTAL ISSUES

8:00 - 8:30	Registration
8:30 - 9:15	**HIBERNIA - ENVIRONMENTAL/SOCIO-ECONOMIC IMPACT ASSESSMENT PROCESS** Charles Lester Department of Mines and Energy Government of Newfoundland & Labrador CANADA
9:15 - 10:00	**ENVIRONMENTAL IMPACT ASSESSMENT AND OFFSHORE PETROLEUM ACTIVITIES IN NORWAY** Jan Borresen Ministry of Petroleum and Energy NORWAY
10:00 - 10:30	COFFEE BREAK
10:30 - 11:15	**OFFSHORE EVACUATION SYSTEMS** Daniel P. O'Brien, C.R.S.P. Seascape Systems Limited CANADA
11:15 - 12:00	**CERTIFICATION OF OFFSHORE INSTALLATIONS REGULATORY REQUIREMENTS** Walter Bobby Canada-Nfld Offshore Petroleum Board CANADA
12:00 - 12:30	Panel Discussion with the Day's Speakers
	Moderator: Eric Gray Shawmont Newfoundland Ltd.

SESSION III - COST EFFECTIVE PRODUCTION

7:30 - 8:00	Registration
8:00 - 8:45	**EFFECT OF OIL PRICES ON THE DESIGN OF OFFSHORE PROJECTS IN THE 1990s** Michael J. Strong NewOcean Contractors Limited CANADA
8:45 - 9:30	**RISK MANAGEMENT AND OFFSHORE PROJECT COSTS** Tony Mackay MacKay Consultants SCOTLAND
9:30 - 10:15	**THE CONCEPTION AND DEVELOPMENT OF THE REVISED HIBERNIA DECK CONFIGURATION** Tomm Lund Aker Engineering A.S. NORWAY
10:15 - 10:30	COFFEE BREAK
10:30 - 11:15	**COST EFFECTIVE CONCRETE FLOATERS** Frode Jensen North Atlantic Contractors CANADA
11:15 - 12:00	**TRENDS IN CAPITAL AND OPERATING COSTS - THE UK EXPERIENCE** Gareth Lewis-Davies Wood Mackenzie and Co. SCOTLAND
12:00 - 12:30	Panel Discussion with the Day's Speakers Moderator: Stewart Strong NORDCO Limited
1:00 - 3:00	Closing Luncheon Guest Speaker: **JOHN MACDOUGALL, M.P., Timiskaming, & Parliamentary Secretary to the Honourable Jake Epp, Minister of Energy, Mines & Resources Government of Canada**

CONFERENCE OPENING ADDRESS

by

THE HONOURABLE REX GIBBONS
MINISTER OF MINES AND ENERGY
GOVERNMENT OF
NEWFOUNDLAND AND LABRADOR

It has now been one year since I became Minister of Mines & Energy and already this is my second NOIA Conference. Last year I had the privilege of opening the exhibition at Memorial Stadium. This year you do me the honour of asking me to give the opening address at your conference. It is indeed a pleasure to be here and to participate in the proceedings.

The theme of this year's conference, **"An Assessment of the Economic Environment in the 1990's"**, is a very relevant and timely one. It is very important to place the economic factors affecting development potential in the Newfoundland and Labrador offshore area over the next decade in perspective. This is particularly true as we stand on the eve of our first development. It is hoped, I am sure, by all in this room, that the coming decade will see the

Newfoundland and Labrador offshore area come into its own, starting with the Hibernia development and continuing with the Terra Nova field and other prospects.

I note with interest the papers you have selected for presentation at this year's conference. Topics focusing on world energy trends, regulatory and environmental issues, and cost effective production should set the stage for what undoubtedly will be very stimulating and productive discussions.

By the topics you have selected, you give recognition that this province's fledging oil and gas industry is but part of an international activity played out in the world arena, and, consequently, subject to the forces and vagaries of world economic factors and conditions. Very often while concentrating on other, probably more technical issues, we tend to forget the importance of factors such as inflation, currency exchange rates, interest rates, and energy supply and demand.

But these are intricate parts of the puzzle that must be assessed in determining the economic viability of a project, and, ultimately, together with other important factors such as reserves, price, concerns for the environment, and technology, dictate whether a project will proceed. So I wish you well in your deliberations and compliment you on your selection of topics.

Status of Hibernia Negotiations

Hibernia has been a long time in coming but I feel confident that this summer will see it arrive at long last. We are not there yet but, over the past year, we have moved the process a long way towards completion - to a point where I believe that all remaining issues can be completed in time for a construction start this year.

Unfortunately, these remaining issues, together with final legal drafting and preparation of the signing documents, may necessitate some extension to the June 30th target that we set last September. I can assure you that any extra time required is because of the complexities of the task and not because of any lack of diligence and desire by all parties involved in the process. In particular, I want to express my gratitude to the Honourable Mr. Jake Epp and his staff in this regard.

I know that you would all very much prefer me to have a more definitive report as to the progress of the negotiations and as to when a final agreement can be expected - and obviously I would be delighted to be able to do so. I am sure you all realize, however, that until the negotiations are finally completed, it would be unwise for me to speculate further. I can only say that all three parties give every appearance of being anxious to complete the process and that the differences are, in my view, capable of early resolution.

As you can appreciate, the process of negotiating and preparing the various binding agreements that began with the signing of the Statement of Principles in 1988 has been a long and arduous one, fraught with very difficult issues and extreme complexities. Just to give you a flavour of the process we have come through on the Newfoundland side alone, setting aside the federal process for a moment, there are in excess of 100 separate agreements and other documents. A tremendous amount of work has already been done by a multitude of committees and advisors.

You will recall that among other things the Statement of Principles provided:

(1) that the companies would negotiate with the province to develop arrangements whereby the production and sale of Hibernia crude oil would be done in such a way as to result in the allocation of income to the Newfoundland offshore for corporation tax purposes;

(2) that the companies would pay a three tier royalty to the province consisting of a gross royalty, a net royalty, and a supplementary royalty;

(3) that the Government of Newfoundland and Labrador would not levy provincial retail sales tax against capital expenditures;

(4) that the provincial retail sales tax on operating costs would be 4%;

(5) that the Government of Newfoundland and Labrador and the Government of Canada would allocate $95 million from the Canada-Newfoundland Offshore Development Fund towards the construction of facilities for certain activities; and,

(6) that the Government of Newfoundland and Labrador would provide $11 million to the project owners in recognition of commitments given in relation to design engineering activities in the province.

All of these commitments require agreements, in one form or another, to be worked out with the project owners. In addition, three separate pieces of provincial legislation had to be drafted in order to implement these agreements.

We have substantially completed the work on many of these agreements, and we are very close on a number of others, with only a few outstanding items and some drafting remaining. Other signs of progress include the establishment of the Hibernia Management and Development Company by the consortium and the issuance of a Production Licence to the consortium which was a prerequisite to the signing of the binding agreements. I also note with encouragement recent positive public statements emanating from the companies respecting their overall confidence in this project.

On the federal side, the issues have been no less difficult or complex. In many respects, even more so. Negotiating a financing package for an $8 billion project is no simple matter, not to mention the lender risk sharing requirements, the drafting of the net profits interest agreement, or the interest assistance provisions.

Much attention has been directed over the past year to the level of industrial and employment benefits flowing to the province and to Canada, generally. Unfortunately, this is the one major area in which final agreement has not as yet been reached. Nevertheless, significant progress has been made in this area towards final resolution of the outstanding items.

With respect to industrial and employment benefits, our provincial strategy relates to both the qualitative and quantitative aspects of the various work packages which make up the entire Hibernia project. The Hibernia project means more for this province than the creation of construction jobs, as important as they will be. It represents an opportunity, if we stress the qualitative and strategic nature of the work packages to be done in this province, to position ourselves for subsequent field development.

In a more general sense, the Hibernia project, and our involvement in it, will represent the beginning of a new industry in this province and will provide the opportunity to not only revitalize our economy but also to make fundamental, qualitative changes in its structure. The task of participating, in a major way, in a world class engineering feat - that of building a production platform and installing and operating it in the North Atlantic 315 kilometres from shore - will be a challenge in the extreme. The technical and contract performance standards required by the Hibernia consortium from the local business community will leave successful participants changed and galvanized.

This is why we have assigned high priority to approving projects under the Canada/Newfoundland Offshore Development Fund which better position this province and enhance the opportunities for Newfoundlanders and Labradorians to participate in offshore oil and gas exploration, development, and production activities. This is why we will continue to encourage research and development in petroleum-related fields which lead to the development of greater provincial technical expertise in the offshore.

To date, nineteen (19) projects have been approved under the Offshore Development Fund for a total commitment of nearly $238 million. This includes the amount of $95 million approved in July 1988 as part of the Hibernia Statement of Principles. Announcements of additional funding will be made very shortly. A more complete list is appended to my written text for your reference.

To my knowledge, never before, not even in the North Sea, not in Norway or the United Kingdom, was so much attention paid in the early offshore projects to putting in place legal requirements and other assurances that significant industrial and employment benefits would flow to the local economy. I can assure you that we are working hard and long to do all that is possible to bring the maximum level of benefits to this province from the Hibernia project.

Let me further assure you that we, as a province, will continue our efforts to maximize benefits flowing to the province over the entire life of the project and particularly during the development phase. We will be monitoring all activities very closely, particularly the letting of contracts and related employment opportunities, and we will continue to do all in our power to ensure that the level of benefits promised not only materialize but are exceeded. We do not take this task lightly and we will pursue it diligently. As I have said before, we are not prepared to accept anything less than our fair share of benefits from the project. We remain committed to this objective, and, as such, it will be one of the main focuses of our monitoring activities.

Terra Nova Project

Jim Stanford, President of Petro-Canada recently stated that approvals for other offshore developments will come easier after we reach agreement on Hibernia. Not surprisingly, the frontrunner, as Mr. Stanford sees it, is the Terra Nova oil discovery. As a government, we have high expectations for the Terra Nova field. Favourable drilling results since 1984 have seen reserve estimates for the Terra Nova field increase dramatically from under 100 million barrels to slightly over 400 million barrels, at the 50% probability level. We have confidence that eventual production from the field will exceed 100,000 barrels of oil per day.

The Terra Nova Consortium, headed by Petro-Canada as operator, continues to evaluate reserves and alternative production facilities, including semi-submersible, monohull, and floating concrete systems. The province believes that consideration should also be given to the GBS option. These and other studies being carried out by the consortium could enable it to decide by fall whether it wishes to proceed to the next stage in the project and submit a development application.

We have already started planning work with respect to the Terra Nova project and the challenges it offers. We intend to develop and carefully study the various policy alternatives. Preliminary evaluations indicate very attractive project economics. We will be meeting with Petro-Canada and other members of the consortium in the near future to discuss matters of mutual concern.

Offshore Oil and Gas Activity

Offshore, Petro-Canada is finishing operations at the King's Cove well site, using the Sedco 710. I am not aware of any firm plans for additional drilling during 1990.

It is anticipated that a two to three month seismic exploration program, with a value of about $5 million, will be carried out on the Grand Banks this summer. The program will be conducted on exploration licences issued as a result of the 1989 land sale and could result in exploratory drilling in 1991 or 1992.

Over the 24 year period of offshore activity, there has been a total expenditure of about $3.7 billion on drilling, seismic and other work. This activity has resulted in 20 significant discoveries, with 5 on the Labrador Shelf and 15 on the Grand Banks. These discoveries amount to discovered oil and gas resources of about 1.6

billion barrels and 7.5 trillion cubic feet respectively. Low oil prices continue to have a negative effect on offshore exploration.

Rights Issuance

In the offshore area, the industry nominates lands and gains interests through a cyclical rights issuance process. The 1989-90 cycle started with a call for nominations in October, which closed at the end of December. At the end of March, there was a second call for nominations respecting lands in the Jeanne D'Arc Basin area that recently reverted to the Crown. A July call for bids will likely result in an awarding of licences during November.

This land sale is the largest ever for Newfoundland, from an area standpoint. At least 14 parcels involving 3 1/2 million hectares are being offered in four separate geological basins: Jeanne D'Arc, the Flemish Pass, the Whale Basin and offshore the west coast.

Significant new exploratory drilling in the early 1990's should take place on lands held under new exploration licences issued as a result of the 1988 and 1989 land sales and the sale proposed for 1990.

Government continues to closely monitor the process and encourage appropriate levels of rights issuance. This is designed to ensure that industry is provided ample opportunity to explore and prove up reserves.

View of the Future

There seems to be a generally held view in the oil industry that the long-term future of the Canadian oil and gas industry is in the frontiers. We, in this province, hope this expectation materializes and I am confident that the Newfoundland and

Labrador offshore area will play a leading role in the fulfilment of this expectation.

It has also become clear, and I had an opportunity to observe this first hand during my recent visit to the Offshore Technology Conference in Houston, that the industry's focus is on developing more efficient techniques and new technologies to cut costs and protect the environment. New technology continues to play an important role in assisting offshore operators to meet increasing engineering and economic challenges.

I feel very strongly that if the future of the Canadian oil and gas is in the frontier then it is clear that this future will become a reality through new technological innovation.

Whether these technologies include topside redesign and weight and cost reductions, or whether they include horizontal drilling and more efficiency in the drilling process, using the latest technology in the best way is often critical to profitability. In my opinion, emphasis will continue to be placed on finding ways to reduce costs in light of depressed oil prices, and Newfoundland will most certainly benefit as a result of the application of the new technologies.

So, it is with great pleasure that I welcome you to our province and declare this conference officially open.

Thank you.

APPENDIX A

CANADA-NEWFOUNDLAND OFFSHORE DEVELOPMENT FUND
TOTAL COSTS OF APPROVED PROJECTS
PUBLICLY ANNOUNCED AS OF MAY 31, 1990

PROJECT		PROJECT COSTS
1.	Centre for Earth Resources Research	$27,100,000
2.	Offshore Survival Centre	$6,300,000
3.	Skills Training Projects	$3,000,000
4.	Computer Aided Design Facility in Engineering	$1,150,000
5.	Atlantic Accord Career Development Awards Program	$3,000,000
6.	Centre for Offshore and Remote Medicine and Telemedicine	$2,843,500
7.	Centre for Cold Ocean Resources Eng. (C-CORE)	$5,000,000
8.	Centre for Excellence in Marine Signal Processing (NORDCO)	$7,400,000
9.	Research and Development Block Fund	$5,000,000
10.	Offshore Tech. Transfer Opportunities Program	$5,000,000
11.	Petroleum Technology Training Program	$21,100,000
12.	Industrial Infrastructure Planning Program	$1,300,000
13.	Enhancement of Offshore Fabrication Capability of Marystown Shipyard	$36,500,000
14.	Access Road to Cow Head Oil Rig Repair Facility	$614,057
15.	Administrative Support: Canada-Newfoundland Offshore Development Fund Committee	$500,000
16.	Wave Generator System: Institute for Marine Dynamics	$3,500,000
17.	Marine Offshore Simulator Training (MOST) Centre	$12,818.497
18.	Memorial University: Institute of Social and Economic Research	$300,000
19.	GBS Graving Dock and Main Support Frame Assembly Facility: Come-By-Chance	$95,000,000
	TOTAL	$237,426,054

CONFERENCE PAPERS

SPEAKER : **ANTHONY E. REINSCH**

COMPANY : **CANADIAN ENERGY RESEARCH INSTITUTE**

LOCATION: **CALGARY, ALBERTA**

TOPIC : **WORLD OIL MARKET PROJECTIONS: 1990-2005**

BIOGRAPHY: Anthony Reinsch is Vice-President of the Canadian Energy Research Institute in Calgary, Alberta.

Mr. Reinsch attended the University of Calgary, and received his B.A. in Economics in 1976 and his M.A. in 1977. He received his M.Sc. in Economics from the London School of Economics and Political Science in 1978 and engaged in doctoral studies in Economics at the University of Western Ontario from 1978 to 1980.

From 1974 to 1984, Mr. Reinsch lectured at Canadian colleges and universities in the areas of economic theory and applied microeconomics. From 1980 to 1982 he was an economic analyst with Ontario Hydro, and from 1982 to 1984 he was Senior Economist - Intergovernmental Finance in the Fiscal Policy and Economics Branch of the Alberta Treasury. Prior to joining CERI, he held the position of Senior Economist - Commodities and Industries in the Economics Department of the Bank of Montreal in Toronto. Mr. Reinsch became Manager of CERI in April 1986. He assumed his present position on April 1, 1988.

As Vice-President of the Canadian Energy Research Institute, Mr. Reinsch is responsible for coordinating the Institute's research program.

WORLD OIL MARKET PROJECTIONS:
GAUGING THE UNCERTAINTIES

1. Introduction

For the oil industry, the 1980s ended on a strong note. Crude oil demand had returned to a strong upward trend, accommodating OPEC production growth and non-OPEC capacity volumes without apparent price weakness. The key issues of that decade--chronic price instability in the face of rising non-OPEC production, weak demand growth, and lack of solidarity within OPEC--appeared to have been worked through.

However, three new issues have come to the fore which present new challenges to the industry. First and foremost is the rapid ascendence of environmental concerns to the top of the political and social agenda in the industrialized world. Second is the political and social revolution taking place in the Soviet Union and Eastern Europe, the outcome of which is anything but clear. Third is a growing concern over the excess capacity margin being carried by OPEC. This latter factor is prompting many analysts to call for a third oil price shock, perhaps in the 1994-96 time frame, based on the inability of OPEC to add capacity at a rate sufficient to accommodate expected market growth.

The market fundamentals which drove the world oil market over the 1980s will be key to developments over the coming decade. On the demand side, two factors are of particular importance. First is the recovery in crude oil demand growth experienced over the last five years. After four years of significant negative demand growth in the early 1980s, oil demand growth has averaged between 2.0% and 2.5% over the 1986-90 period[1]. This trend does not represent so much a relinking of oil product demand to economic activity, as much as it reflects the price sensitivity of oil demand to crude oil prices.

The latter half of the 1980s has witnessed an increase in the price responsiveness of oil demand, brought about by the industrial sector adjustments made in response to the two oil price shocks of the 1970s. Consumers are better equipped to move away from relative price changes; over the past five years, we have seen this ability brought to bear in favor of oil product consumption.

The second demand factor is the so-called lightening of the demand barrel. Heavy fuel oil demand has fallen over the last decade at the expense of gains in gasoline and middle distillates demand, not only in the industrialized countries but in the non-CPE world as a whole. For the purposes of this discussion, the important observation is that a larger component of world oil demand is being centered on those product categories for which there are few available substitutes. This would tend to suggest that oil demand should become increasingly resilient to regulatory, price and income fluctuations as we move through time.

On the supply side of the equation, the key market factor continues to be the expected decline in production from the large non-OPEC producing regions. This suggests that global crude oil production will continue to swing back to OPEC and, in particular, to the Persian Gulf producing nations.

Figure 1 provides proven reserves and reserves life indices for selected key oil producing nations. The Persian Gulf producers show reserves life indices in excess of 100 years; even if one questions the validity of the reserves figures, the order of magnitude is correct. For the non-OPEC producers, the reserves life index from proven reserves is under 15 years for countries such as the United States, Canada, and Norway/UK. This does not mean that these regions will run out of oil after 15 years, rather that production levels can be expected to decline as reserves additions fail to replace production, requiring a gradual decline in output levels to maintain a reserves-to-production ratio in the 8 to 10 range.

The above factors suggest that OPECs dilemma--stagnant demand in the face of rising non-OPEC output, requiring tight production restraint to protect oil price levels--may indeed be in the past. Since the price crash of 1986, OPEC has been able to not only retain its market share, but to consistently increase output to fill the gap between rising demand and flagging non-OPEC production. OPEC production has grown by over 5.0 MMb/d since the early 1980s, accounting for virtually all of the incremental market growth over that period.

2. Reference Case Market Projection[2]

Our reference case market projection is based on what we believe to be a reasonable set of assumptions regarding world economic growth, demand trends, non-OPEC supply capability, and so on. It is a "no surprise" or business as usual scenario, representing market development in an environment free of shocks and discontinuities.

The key input variable in projecting oil prices is the production profile for OPEC. In the reference case, OPEC production is assumed to continue the steady growth trend exhibited over the last three years. OPEC production increases from 22 MMb/d in 1990 to 31 MMb/d in 2000 and 36 MMb/d in 2005 (see Figure 2). It is important to note here that this outlook assumes that the Organization is able to add to current productive capacity over the coming decade. This issue is discussed further in Section 3.

Under this scenario, OPEC regains the dominant share of the world crude oil market by 1994. OPEC market share reaches 45% by 2000 and 50% by 2005, versus roughly 35% today. The resulting price profile has oil prices reaching \$26.10 per barrel by 2000 and \$29.20 per barrel by 2005 (see Figure 3).[3]

With world oil demand growing on average at just under 1.0 MMb/d over the projection period--reaching 74.5 MMb/d by 2000 and 78.8 MMb/d by 2005, versus 67 MMb/d in 1990--the growth in OPEC production is accommodated in part by the projected decline in non-OPEC production (see Figure 4). Non-OPEC output peaks in 1993-94 at just over 23 MMb/d (crude oil only) and declines steadily to under 19 MMb/d by the end of the forecast period. This profile reflects the inability of the new producing regions to make up for the projected decline in U.S. and Norway/UK production, among other regions, over the period.

3. Alternative Scenarios

While the reference case is our most likely scenario for the development of the world oil market, the real importance of a reference case is that it carries the highest probability of being least wrong. Many factors can impinge on the world oil market over the next 15 years, shocking it in ways which we cannot predict. In this paper, we examine two such oil market developments.

3.1 High Non-OPEC Resource Case

The ability of the non-OPEC nations to maintain, or expand, production in the future is one of the key uncertainties affecting the evolution of crude oil prices. In this scenario, we increase the estimate of non-OPEC, non-CPE remaining reserves from a modal estimate of 307 billion barrels (used in the reference case and all other scenarios) to a 5 percent probability estimate of 490 billion barrels. All other assumptions, including the OPEC production profile, are as in the reference case.

The impact on oil prices is significant (see Figure 3). World oil prices increase to only $22 per barrel by 2000 and $23.50 per barrel by 2005. This is considerably below the reference case price of $29.30 per barrel in 2005, reflecting the dominance of enhanced non-OPEC oil production over the positive demand response resulting from the lower price track.

Under this scenario, non-OPEC production peaks later (1998-99 versus 1993-94) and at a higher level (25.4 MMb/d versus 23.2 MMb/d) than under the reference case (see Figure 4). The larger ultimate potential resource base in effect offsets the lower drilling activity associated with the lower price track.

This scenario was motivated on the basis of a higher ultimate potential resource base in the non-OPEC producing regions. The scenario could equally reflect the benefits of continued technological advances in seismic and geological/geophysical techniques, or advances in enhanced oil recovery applications. The key point is the sensitivity of the price profile to the ability of non-OPEC producers to prove up and produce new reserves.

3.2 Low OPEC Capacity Scenario

While this is always a difficult subject to analyze, reliable sources suggest that current OPEC capacity is roughly 27.5 MMb/d, down from 32 MMb/d in 1983 and peak capacity of 39.2 MMb/d in 1979.[4] At April production levels of 23.5 MMb/d, this leaves a near-term capacity margin of only 4.0 MMb/d or some 8 percent of non-CPE world oil consumption. With annual demand growth of 2.0-2.5% (or 1.0 MMb/d) expected over the next 3-4 years, it is little wonder that capacity additions are front and center on the OPEC agenda.

Plans have been put forward for significant capacity additions over the next three years which, if successful, would bring OPEC capacity to 33 MMb/d. In this scenario, we assume that this capacity is brought on stream, but that the subsequent round of additions--which would entail new field development and considerable engineering and construction expenditure--is not forthcoming until later in the forecast period.

OPEC production under this scenario reaches an effective ceiling in 1997, adding only 2.6 MMb/d of incremental capacity over the remainder of the forecast period (see Figure 2). With OPEC capacity capped, prices rise quickly and reach over $32 per barrel in the 2003-04 period (see Figure 3). The upward trend is gradually tempered by slower demand growth. However, the strong non-OPEC production response which turned the market down in the

1980s fails to appear--rather, the speed of decline of non-OPEC production is simply decreased.

4. Implications for Canada[5]

Building on work done elsewhere at CERI, the reference case price profile can be applied to Canadian resource development, generating a development profile for conventional and nonconventional sources of Canadian crude oil liquids. This analysis is done under the assumption that projects are not initiated until the market price exceeds the internal hurdle price for economic development of the project, abstracting from possible government support.

As shown in Figure 5, the dominant trend in the Canadian oil market is the decline in light-medium conventional oil production, from over 300 MMb/y in 1990 to under 160 MMb/y in 2005. Under the reference case price profile, little additional nonconventional crude oil is brought into production until after the turn of the century. Indeed, it is the onset of frontier offshore production--both in the East Coast offshore region and the Beaufort--that turns the production profile back up.

The implications for Canada's light oil balance is significant. The decline in light oil production, combined with steady demand, yields a light oil deficit that peaks at just under 1.0 MMb/d in the 2001-03 period. This oil deficit, and the reliance on foreign crude oil sourcing and exposure to terms of trade pressures which it represents, lies behind movements by the federal and several provincial governments to advance the development of Canada's frontier and nonconventional crude oil sources.

5. Conclusions

There are a number of conclusions that can be drawn from these results. First, our analysis suggests that the fragility of oil prices, which accounted for the unusual conservatism in oil exploration and development over the latter half of the 1980s, is likely to dissipate as we move through the 1990s.

Second, a tighter supply-demand balance in the market will reintroduce the potential for engineered real price gains. It is important to note here that the strategy of gradual price-production gains over the 1990s proved superior, from both a revenue and market growth standpoint, to all other scenarios examined over the course of the research program.

This forms our third conclusion, that these results underline the revenue dominance and strategic importance of a sustained, gradual price-production strategy on the part of OPEC. Having witnessed first hand the responsiveness of oil demand to price fluctuations and the resilience of new sources of non-OPEC supply once brought into production, OPEC can be presumed to have little interest in a third price shock on the world oil market.

Fourth, the production profile suggested for OPEC in the reference case requires the addition of significant production capacity over the 1995-2005 period. While no one questions that OPEC possesses the physical reserves to meet this production profile, there is growing concern that the Organization may lack the financial reserves to implement an aggressive capacity expansion plan. The issue of OPEC surplus capacity is one of the key risk variables in the 1990s.

Fifth, the high non-OPEC resource scenario heightens the risk of a second oil price collapse and a collapse of OPEC down to a smaller, more homogenous group. Such a development could add another element of stability to a market which appears headed into a decade of growth and relative prosperity.

Finally, for Canadian producers, the reference case projection contained in this paper suggests that the industry can look forward to improved crude oil netbacks and a more profitable market as we move through the 1990s.

Footnotes

[1] International Energy Agency, Oil Market Report, selected issues.

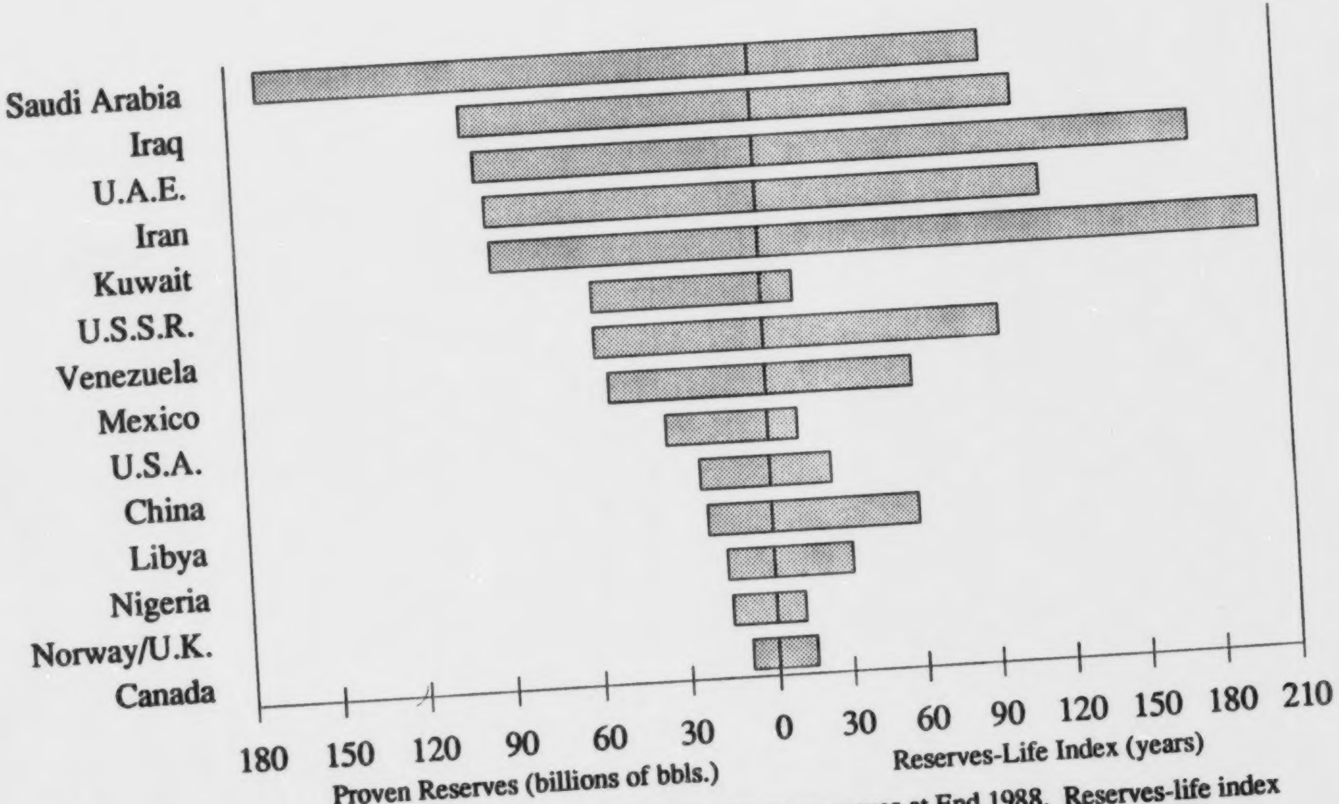
[2] The material in this section is abstracted from CERI Study No. 34, World Oil Market Projections: 1990-2005, by A.E. Reinsch and M.A. O'Reilly, March 1990, Chapters 2 and 3.

[3] All prices referenced in this paper are for West Texas Intermediate crude oil delivered at Cushing, Oklahoma, expressed in constant $1989 (U.S.).

[4] Petroleum Intelligence Weekly, March 12, 1990, p. 7.

[5] The development profile for Canadian crude oil liquids is sourced from CERI Study No. 31, Canadian Crude Oil Supply/Demand Balances, by J. Tanner and A.E. Reinsch, August 1989, Chapter 5.

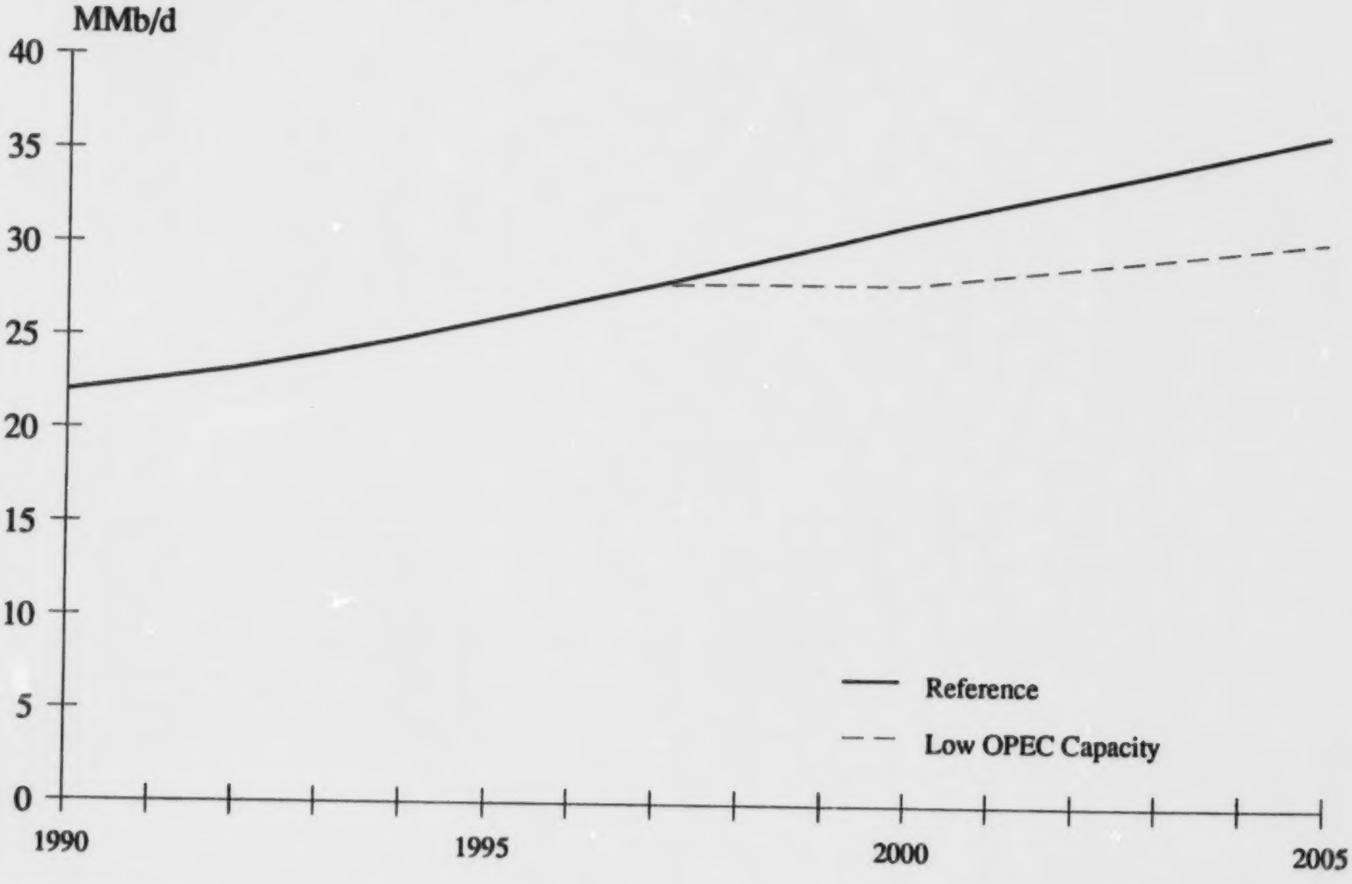
Figure 1
Proven Reserves & Reserves-Life Indices
Selected Countries



NOTE: Proven reserves at End 1988. Reserves-life index based on 1988 average daily production rate.

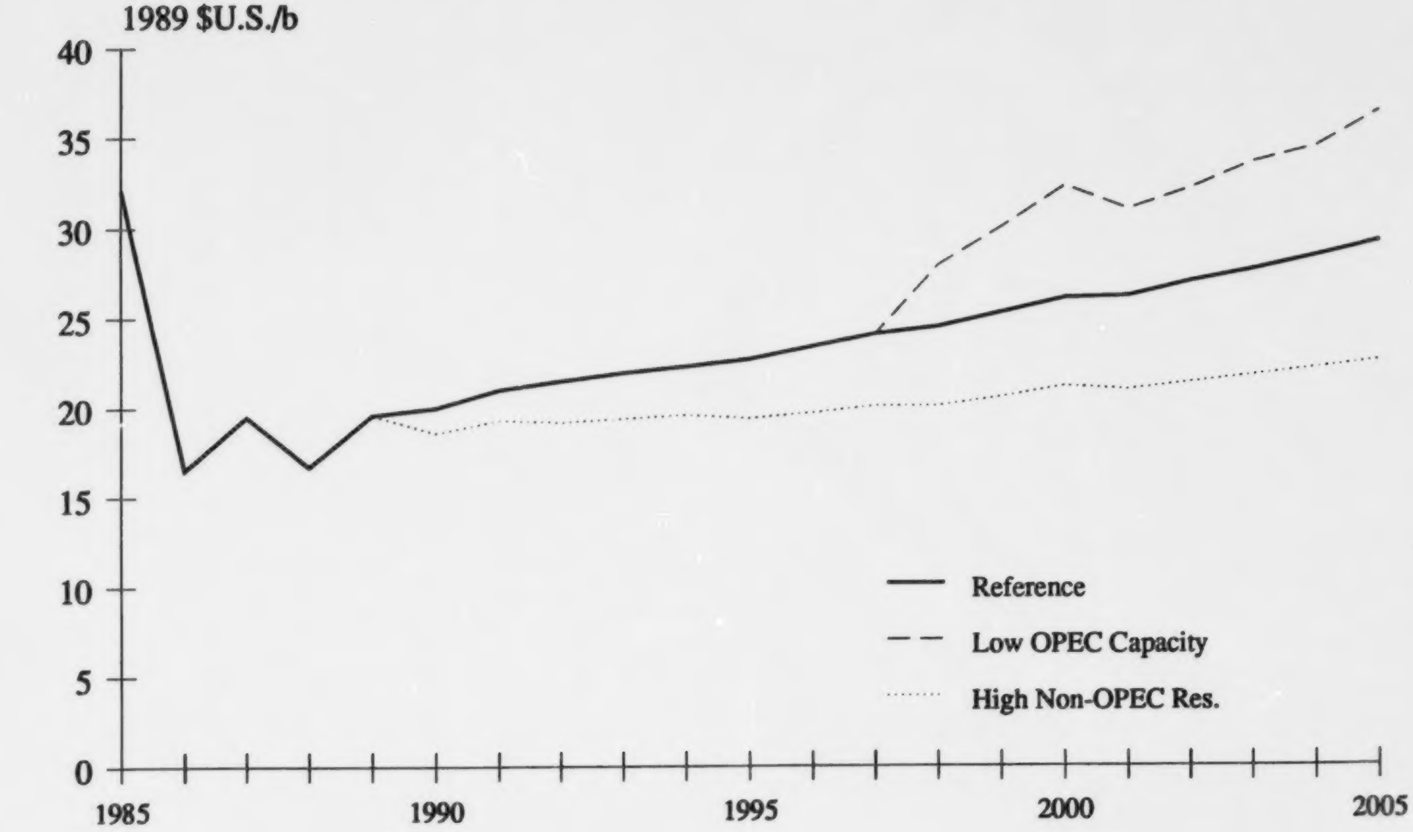
SOURCE: BP Statistical Yearbook,
PIW, Oil and Gas Journal, CERI.

Figure 2
OPEC Production Profiles



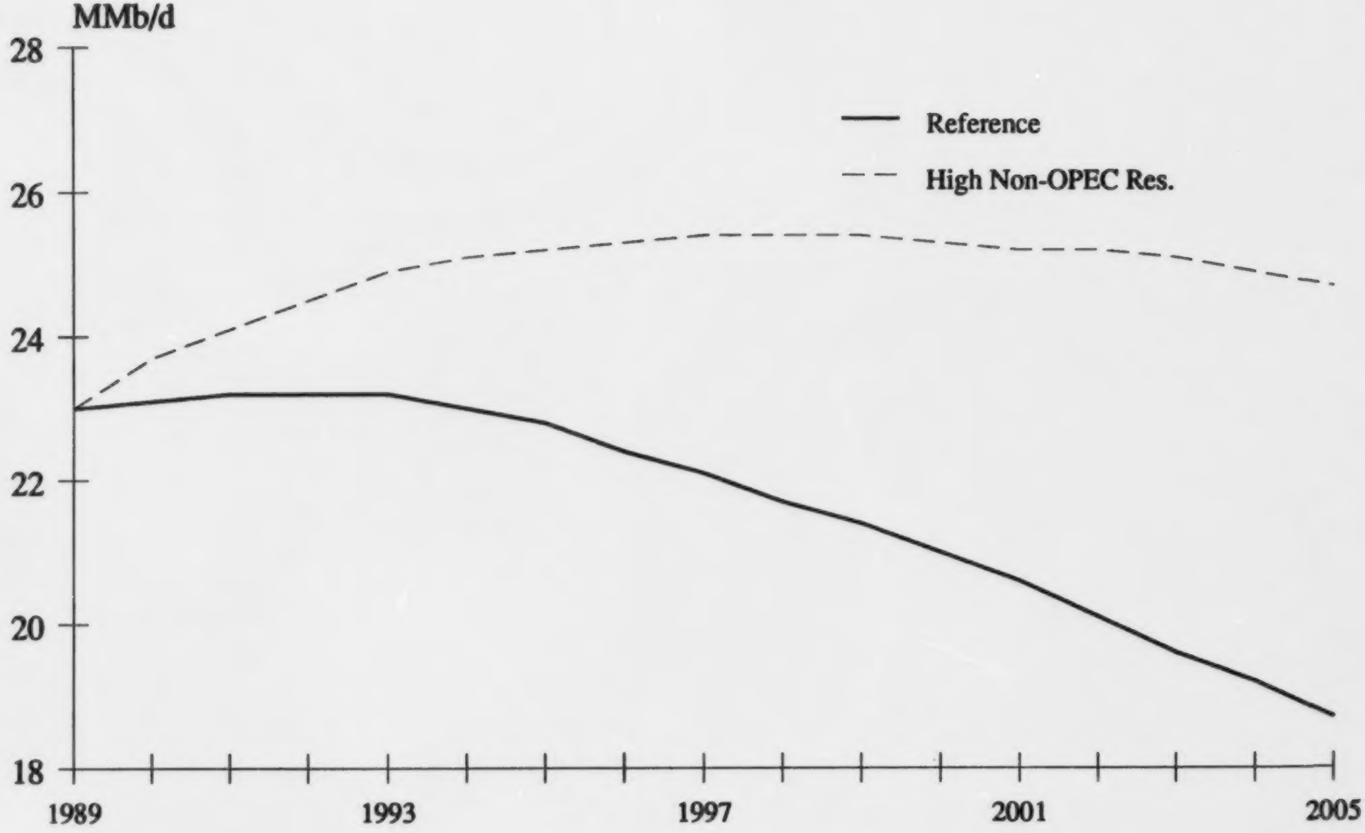
SOURCE: CERI.

Figure 3
World Oil Price Projections



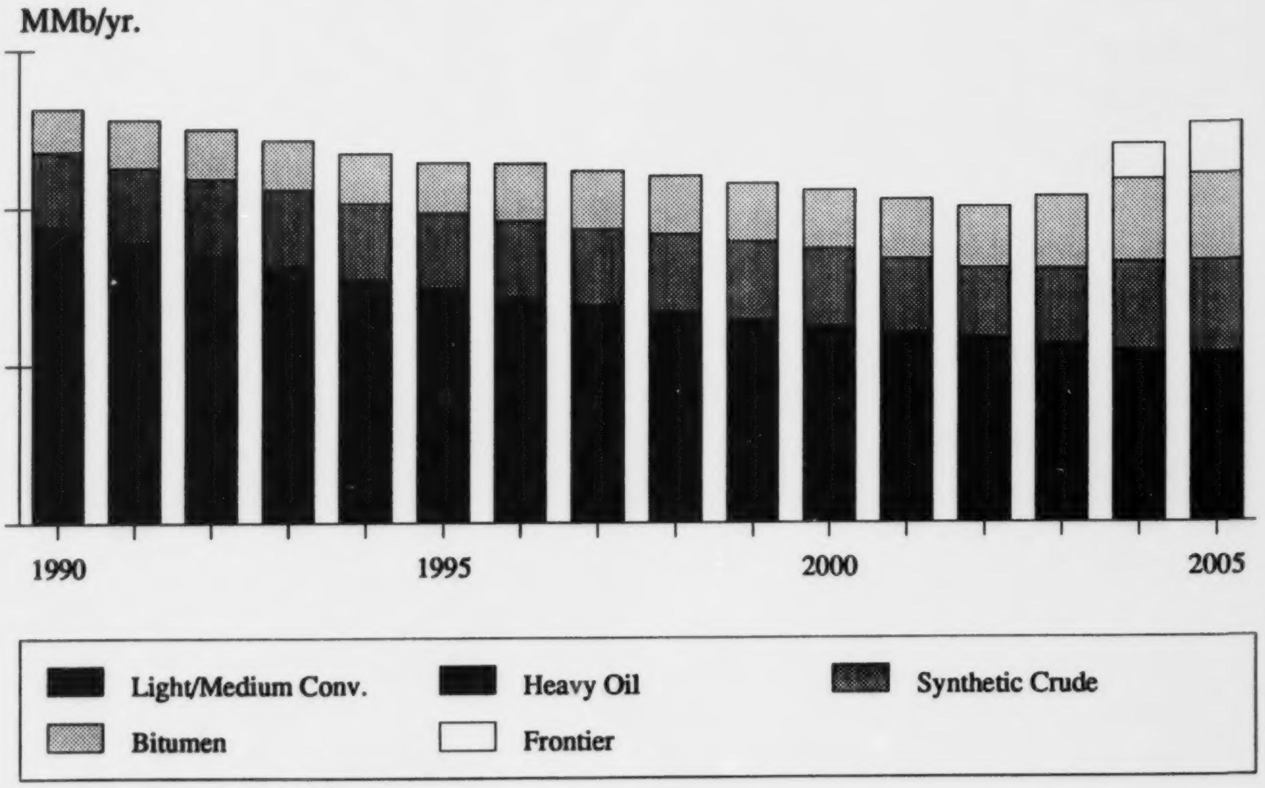
SOURCE: CERI.

Figure 4
Non-OPEC Production Profile



SOURCE: CERI.

Figure 5
Canadian Resource Development Profile
Reference Case Prices



SOURCE: CERI.

SPEAKER : CYRIL STURGE

COMPANY : DEPARTMENT OF MINES AND ENERGY
GOVERNMENT OF NEWFOUNDLAND AND LABRADOR

LOCATION: ST. JOHN'S, NEWFOUNDLAND

TOPIC : OIL SUPPLY AND DEMAND AND PRICING ISSUES

BIOGRAPHY: Mr. Sturge graduated from Memorial University in 1970 with a degree in Business Administration. After a brief stint with the Newfoundland Government, he returned to Carleton University in 1973 and graduated with a Master of Arts (Public Administration) in 1975.

Since joining the government in 1976, Mr. Sturge has held several senior management positions with the Department of Finance and the Petroleum Directorate. Mr. Sturge currently holds the position of Director, Economic Analysis with the Department of Mines and Energy where he is responsible for activities related to energy markets and programs.

ABSTRACT

OIL SUPPLY AND DEMAND AND PRICING ISSUES

Oil supply and demand and the price of crude oil are intricately linked. On the demand side, we have seen world oil consumption drop from a high of 63 Mbd in 1979 to a low of 56 Mbd in 1983 and only in the past year or so is demand making a strong comeback. Since 1984 the worlds reserves of oil have increased by about 300 billion bbls. Oil prices on the other hand dropped to a low in 1986 that can only be compared with prices reached in 1973.

This paper will look at the relationship between supply, demand and prices historically and used the findings to attempt some predictions about the future. The paper will be divided into three sections. Section one will look at those issues that have had an impact on oil demand world wide over the past decade including price, conservation, substitution, the environment, economics and security of supply. These issues, if indeed they are still issues, will then be reviewed in light of their future impact on demand. Section two will look at the supply side of the equation and draw attention to OPEC and non OPEC supply and the role each of these groups have played and will continue to play. The final section will bring together the supply and demand arguments and show how these factors have influenced price in the past and the impact they could have on future prices.

OIL SUPPLY, DEMAND AND PRICING ISSUES

INTRODUCTION

Supply, demand and price are the essential ingredients of the free market system. When supply and demand are allowed to find their own level without interference, the price established is usually a fair one to the producer and the consumer.

Today I am going to talk about supply, demand and price as they relate to the petroleum industry.

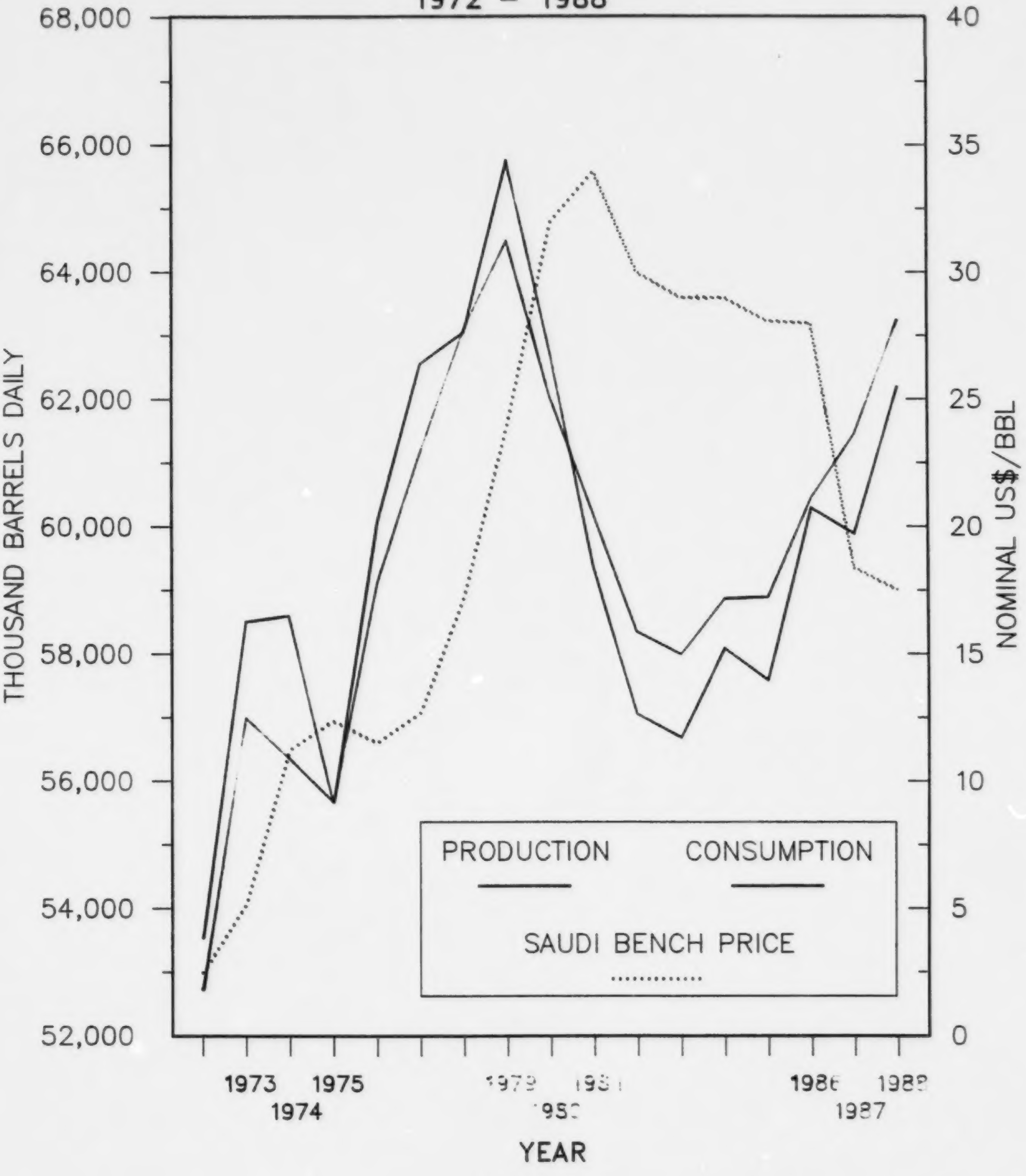
My talk is divided into three parts -
First, I will look at the history,
Second, the current and near current situation, and
Finally, the future, which I do with great trepidation.

Let me begin by looking at the historical relationship between oil demand, oil supply and price. This should help bring these factors into focus and provide a base to look at future developments.

GRAPH I

COMPARISON OF TOTAL WORLD OIL PRODUCTION, CONSUMPTION AND PRICE

1972 – 1988



SOURCE: THE BRITISH PETROLEUM COMPANY
STATISTICAL REVIEW OF WORLD ENERGY
JUNE 1989

HISTORY

OPEC increased prices for the first time in 1973. (See Graph 1) Demand dipped for a short period in 1974 - 1975. From that point on, world demand increased steadily at an average annual rate of 3.7% peaking in 1979 at 64.5 million b/d. Production was more than 67.0 million b/d. By 1980 demand started to drop, however, prices continued to increase. Saudi light, the bench mark crude of the day, climbed to $28.00 (US) bbl. in the last half of 1980 and peaked at $34.00 (US) in 1982. OPEC produced 31.5 million b/d in 1979 equivalent to 48% of total world production and enjoyed annual revenues of $195.0 billion. The oil producing countries, especially those in the middle east, had huge cash surpluses. Other governments were running deficits trying to provide basic services.

All in all 1979 was a very good year for the petroleum industry. Demand was increasing at such a fast pace that the US and many countries in Western Europe were experiencing supply problems. There were line ups at the gas stations in California and New York. Rationing was introduced in many parts of the United States. Even some of the large oil companies imposed rationing because as one company put it at the time they were experiencing "unseasonal dramatic demand". Oil rigs both offshore and onland were scarce as oil companies continued to pump money into exploration and development. Alberta was the envy of Canada with a special account called the Heritage Fund established to siphon off excess oil revenue excess to their budgetary needs. Many of you will recall that 1979 was the year Hibernia was discovered.

Within a year world demand was down by 3.8%. By 1983, world demand had dropped by 11% to 57.9 million b/d and oil prices were turning soft. OPEC reduced the official price of Saudi light to $29.00 (US) bbl from $34.00 (US) bbl during the last half of 1983. By this time, however, oil was trading at prices below the official price as the spot market gained in importance. It took four years before demand started to show signs of recovery. In 1973, it took only two years. The turn around time, I believe, reflected, in part, the degree of frustration consumers felt for the quantum leaps in oil prices. Demand started to increase again after 1983. OPEC in its determination to maintain, however, price lost sight of the marketplace. Its share of production started to fall in 1980 and bottomed out at 17.2 million b/d in 1985.

Putting the price issue to one side, the organization set out to try to regain some of the markets lost to non-OPEC producers. As part of its strategy OPEC introduced net back pricing and began over producing during the last quarter of 1985. The organization over produced for the first eight months of 1986 causing prices to plummet creating confusion in the market place. For a short period in mid 1986, the spot price for Brent dropped below $10.00 US and Saudi light went down to $11.38 US. The sudden drop in oil prices was as much a concern for the industrial countries, especially those with a strong international banking community, as it was for OPEC. This prompted a return to production restraint for the remainder of the year, but, not before OPECS' market share increased by some 16%.

The petroleum industry went into a slump after 1979 for several reasons.

First, demand dropped because prices climbed to high, to fast. Oil, as an energy source, had priced itself out of the market place.

Price increases of the 1970's and 1980's set into motion a chain of events that led to a marked decrease in energy use intensity. (Intensity defines the relationship between energy use and a countries annual economic output.)

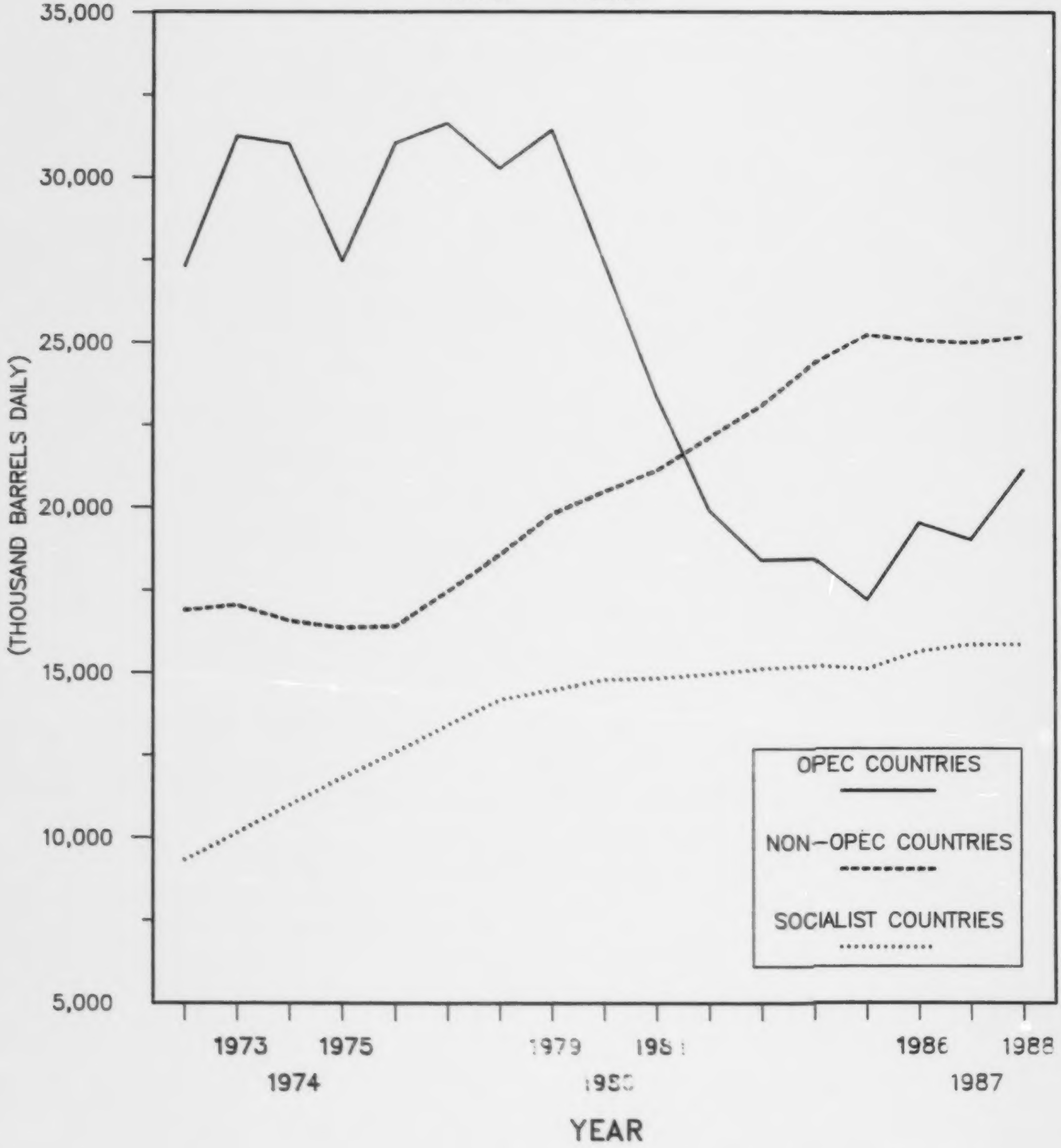
The degree to which North Americans became more energy efficient is revealed by the fact that the intensity ratio dropped to .62 in 1985 from .80 in 1973. In countries covered by the International Energy Agency the ratio dropped from .57 to .45. Consumers substituted oil for other forms of energy that were less costly such as coal, electricity and natural gas. In addition, energy delivery systems became more efficient.

No where was this more evident than in Canada where oil, as a share of total energy consumed decreased from 49 per cent in 1978 to 40 per cent in 1988. In other industrialized countries, oil as an energy source dropped 22% over the 10 year period from 1978 to 1988.

The drop in demand was exacerbated by an increase in supply. Non-OPEC production increased steadily from 1975 onward, encouraged by ever rising prices. The

GRAPH II

COMPARISON OF WORLD OIL PRODUCTION OPEC, NON-OPEC AND SOCIALIST COUNTRIES 1972 - 1988



SOURCE: THE BRITISH PETROLEUM COMPANY
STATISTICAL REVIEW OF WORLD ENERGY
JULY 1989

supply of oil on the market or that could be put on the market at any given time had created a supply glut by the early eighties. Graph number II compares the growth of non OPEC production with OPEC production. Non-OPEC production grew at an average annual rate of 3.75% between 1975 and 1988. By 1988 non-OPEC oil, excluding the Communist countries had climbed to over 25 million b/d from 18.6 million b/d in 1978. Production in Communist countries was up to 15.7 million b/d and climbing. OPECs' share on the other hand bottomed out in 1986 and was on the increase by 1988.

CURRENT AND NEAR CURRENT - EVENTS SINCE 1986

Demand started to move upward again after 1983, albeit, slowly. The pace picked up in 1986. The average annual growth rate, currently at 2.7%, is closing in on the growth rate of 3.7% experienced between 1976 and 1979. In fact the actual number of barrels consumed in 1989, estimated at 65048 million b/d is a record for the industry. In the developing countries, demand is up by 5.8%. Most of this increase can be attributed to the rapid growth of certain South East Asian countries such as South Korea, Tiawan and Hong Kong. OPEC production picked up in 1986 propelled by the initiative to increase market share. Production for 1989 went as high as 24.7 million b/d in December, while production in non-OPEC areas dropped off by as much as 676 thousands b/d. Prices, however, have been on a roller coaster mainly because OPEC production quota agreements have proved to be rather fragile. The agreements are not being adhered to because OPEC continues to experience economic and political problems making production discipline difficult. In addition, over hanging excess capacity, a legacy from the 60's and 70's when demand for petroleum was on steady upward trend, makes it easy for member countries to cheat on their quotas. Oil prices did increase in 1989 and appear to be holding at the $18.00 (US) mark, however, they are still characterized by a great deal of instability. This is evident by the wide swing in prices over the past 12 months. Brent traded below $17.00 (US) a barrel at one point in July 1989 and climbed to a high of just below $23.00 (US) a barrel in January 1990. Despite continued price instability there is a degree of optimism that pervades the industry not felt since the late seventies. The optimism is the result of strong demand that has kept prices at acceptable levels even with the wide swings.

In addition to an increase in overall demand during the last half of the 80's, the supply-demand balance was and will continue to be stabilized by the fact that:

(1) American production continues to fall. It is now close to the point where the United States could import 50% of its daily consumption before the end of the century.

(2) Exports from the USSR have dropped off over the past two years, and,

(3) North sea production was down as the result of maintenance problems and a series of accidents.

The industry is recovering from the shock of 1986 and prices are moving up as demand remains strong. Just how long it will continue is anybody's guess.

Before I begin the third part of this presentation, let me look briefly at some of the issues that will affect petroleum markets in the future.

Economic Growth

Oil demand is influenced by many factors. The most important of these is economic growth. The jury is still out on whether the next few years will see a continuation of the economic growth experienced over the past seven or whether there will be a recession. Most economists, however, are in agreement that if there is a recession it will be a mild one. A recent report on the countries that make up the Organization for Economic Co-operation and Development or the OECD predicted that economic growth will continue. Growth in real GDP, that averaged 3.4% between 1986 and 1989, is expected to continue for the seven largest industrial countries, albeit, at slightly lower rate of 2.75% in 1990. GDP for the remaining OECD countries is forecasted to drop marginally from 3.25 % in 1989 to 2.5% in 1990. In the developing countries economic growth is forecasted to move from 3.3% in 1989 to 4.2% in 1990.

A survey of macroeconomic forecasters, recently carried in the Wall Street Journal shows that 60% do not expect a US recession in the next 3 years. Recent reports on the Canadian economy are calling for a slow down that few expect to turn into a recession.

The prospects for long term economic growth are good if inflation can be controlled to create the right setting for investment.

TABLE I
COMPARISON OF PRIMARY ENERGY SOURCES USED TO GENERATE ELECTRICITY
1978 VS 1988

Energy Source	% of Total Energy	
	1978	1988
Oil	21.7	8.6
Gas	10.6	9.2
Nuclear	10.6	22.4
Hydro	19.8	17.4
Coal	37.3	42.4
Total	100.0	100.0

Source:
B.P. Statistical Review of World Energy

Environment

Public concern for the environment will play an important role in the diversification of energy use and overall energy demand in the future. There are two aspects to the environmental issue. On the one hand the world is becoming increasingly concerned over air pollution, and global warming through the Green House effect. These issues impact on demand. On the other hand there is concern over oil spills and pollution of the environment. These are issues that can affect supply if certain frontier areas are closed to exploration and development. It is difficult to quantify the extent to which these issues will affect the oil markets. Much depends on the will of governments to introduce legislation to control CO^2 emissions and other pollutants and on the price the consumer is willing to pay for a cleaner environment. Canada took a strong stand on the issue in a recent report published by Energy Mines and Resources. The report opened with the statement that "Our goal is to make Canada the most environmentally friendly country in the industrialized world by the year 2000". If other countries make a similar commitment, the impact could be significant for petroleum demand. It will, however, depend on whether oil can again become a major competitor with other fuels for new electrical generation. As Table I shows, oil generated 21.7 percent of the electricity used in OECD countries in 1978 and only 8.6 percent in 1988. Its close competitor coal, generated 37.3 per cent in 1978 and 42.4 percent in 1988. Nuclear and Hydro also gained at the expense of oil over this period.

The environmental issue will also affect the supply side as coastal and frontier states tighten regulations and in some cases cut exploration and development entirely. The Exon Valdez accident has increased the fear of oil spills. States like California and North Carolina have since asked for further safe guards before issuing exploration and development permits.

Eastern Europe

Another issue that can affect the energy industry is the changes now taking place in eastern Europe. As the eastern European economy blends with that of western Europe, the economic restructuring should increase the demand for petroleum as an alternative energy source to coal and nuclear. The extent to which coal burning plants have caused environmental problems in eastern Europe, is only now becoming known. The Chernobyl disaster has heightened awareness, not only in Europe, but, the world, of the dangers of nuclear energy.

Except for the USSR, few, if any of the eastern European countries produce oil and, fewer still, export oil. USSR exports have dropped over the past two years mainly because of lack of investment capital to upgrade and increase existing production capacity and find new sources of supply.

Exploration Activity

The downturn in exploration activity will have an impact on long term supply. Exploration activity took a dip in 1986 that has continued through today. The third quarter 1989 report from the US Energy Information Agency shows that in comparison to 1988, the number of rigs was 3.8 percent lower for OPEC, 23.7 percent lower for non-OPEC market economies excluding the US and 20.3 percent lower for the market economies excluding the US. If the turn around time to bring new fields into production during the eighties that were decreased in the seventies is indicative of the turn around time required in the nineties, then, it will be sometime before new fields affect supply.

US Production

Declining US production and energy security, an associated issue, will be important during the 1990's, as growing U.S. oil import dependency is expected to have a major impact on world oil markets. Forecasters examining the US situation project that in 1990 the US will import between 6.9 and 7.6 million b/d of crude and oil products equating to between 39% and 44% of American consumption. By the end of the century forecasters are projecting imports to increase to between 8.3 and 11.0 million b/d amounting to roughly 46% to 57 % of US consumption. The vulnerable position in which this places the US is of growing concern since much of the additional import requirement will come from the politically unstable Middle East. The US will have a choice - develop new forms of energy and or convert to more secure forms such as natural gas and nuclear.

When I began this talk, I said I would look at the future, but, with trepidation, I am sure you can now understand my apprehension after listening to a review of the history and the issues affecting the marketplace.

FUTURE OUTLOOK

So I am not going to try to forecast supply, demand and price, but I will evaluate several scenarios based on the premise that controlling production means market control. A forecast implies that the future can be predicted while a scenario is based on the premise it is unpredictable.

After the price shocks of 1973 and 1986, demand grew at an average annual rate of 3.7 percent and 2.7 percent respectively. In both cases the increase in demand coincided with economic growth. There seems to be a fairly broad consensus that this relationship will continue and overall demand is expected to grow at between 1 percent and 3 percent annually over the short and medium term.

The environmental factor, the Eastern European situation and the decline in exploration activity are difficult to quantify now. Suffice it to say, each will influence the outcome of the supply/demand equation.

Over the short term, declining US production is not expected to put pressure on the supply demand balance. Slow economic growth and continued improvements in automobile

TABLE II
OPEC INSTALLED PRODUCTION CAPACITY CURRENT AND PROJECTED
MMb/d

	1990	1995 Low	1995 High
Saudi Arabia	7.0	9.0	10.0
Iraq	3.5	4.5	5.0
Iran	3.1	4.0	4.5
Venezuela	2.5	2.9	3.0
UAE	2.4	2.9	3.1
Nigeria	1.9	2.2	2.4
Libya	1.6	1.7	2.0
Indonesia	1.3	1.3	1.4
Algeria	0.8	0.9	1.1
Qatar	0.4	0.4	0.5
Gabon	0.3	0.3	0.4
Ecuador	0.3	0.3	0.3
Neutral Zone	0.5	0.4	0.5
Total	27.9	33.5	37.1

Source: Weekly Petroleum Argus

efficiency should keep demand flat for the foreseeable future. Over the long term, however, policies established by the US Government, to deal with energy security, will determine whether this pressure is alleviated or excerbated.

As demand continues to grow, the outlook for oil prices, over the short and medium term, will depend primarily on the ability of exporting countries, OPEC in particular, to control production capacity. If excess production capacity is to a high, as it was in the eighties when the world was producing at roughly 75% of installed capacity, prices are very difficult to control. Most non-OPEC countries are producing at peak. Consequently, almost 100 percent of existing excess production capacity is controlled by OPEC.

OPEC has a sustainable production capacity of approximately 28 million b/d and produces on the average 22.6 million b/d (Table II) equal to 80 percent of installed capacity. Long range plans call for action to boost sustainable production capacity to 33.5 million b/d on the low side to 37.1 million b/d on the high side by 1995 at a cost of $60 billion.

Graph III was designed to show at what point demand, growing at 1%, 2% and 3%, equates with installed production capacity. Based on OPEC plans, world production capacity is assumed to be fixed at approximately 70 million b/d until 1995 when plans call for an increase of between 5 and 9 million b/d.

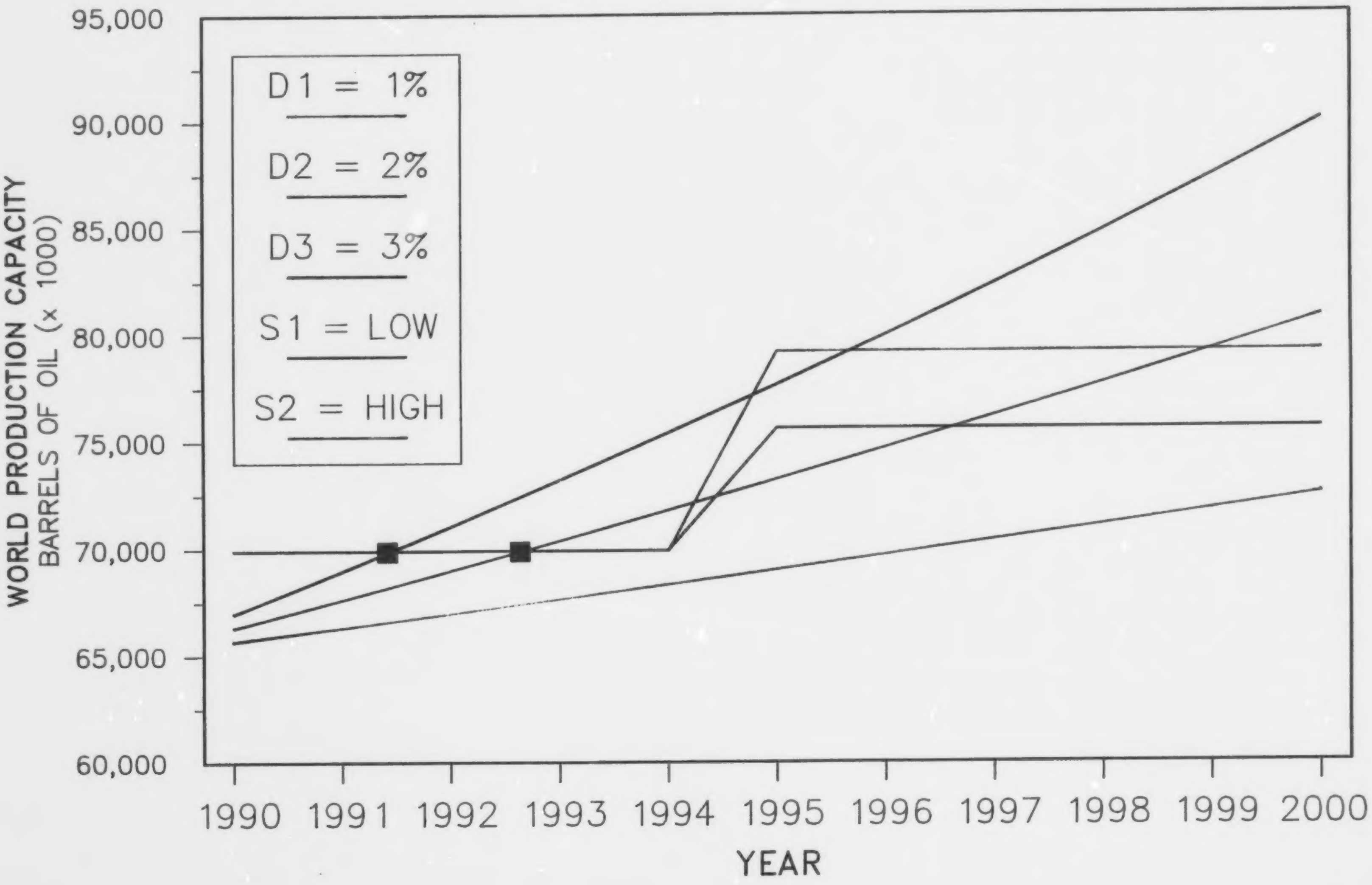
An increase in demand of 1% would allow OPEC to produce at approximately 87 percent of installed capacity of 28 million b/d. This level of production can be accommodated by OPEC's existing surplus capacity of roughly between 5 and 6 million b/d until sometime around the mid nineties. If there is any growth in production from non-OPEC sources, a 1% increase in demand could be accommodated past the mid nineties without a major increase in world production capacity. Based on this scenario, current situation will continue as prices move in the $18.00 (US) to $20.00 (US) range for the next few years. An increase in nominal terms of $2.00 to $4.00 a barrel could occur around the middle of the decade as the supply demand balance tightens and production levels move up. If OPEC's current plans are successful and production capacity is increased by an additional 5 to 9 million b/d by 1995, a major increase in price could be delayed until the turn of the century.

An increase in demand of 2% would force OPEC to produce at 100% of installed capacity sometime between 1992 and 1993 and speed up the installation of additional production capacity. Prices would be forced up sharply between 1993 and 1995.Some relief could come from non-OPEC sources as demand forces prices up encouraging production. Over the longer term, the additional capacity schedule to come on stream in 1995 will help prices settle down.

A 3% increase in demand would force OPEC to produce at 100% of installed capacity between 1991 and 1992. There would be little time to adjust production in the

GRAPH III

COMPARISON OF WORLD PRODUCTION CAPACITY AND DEMAND



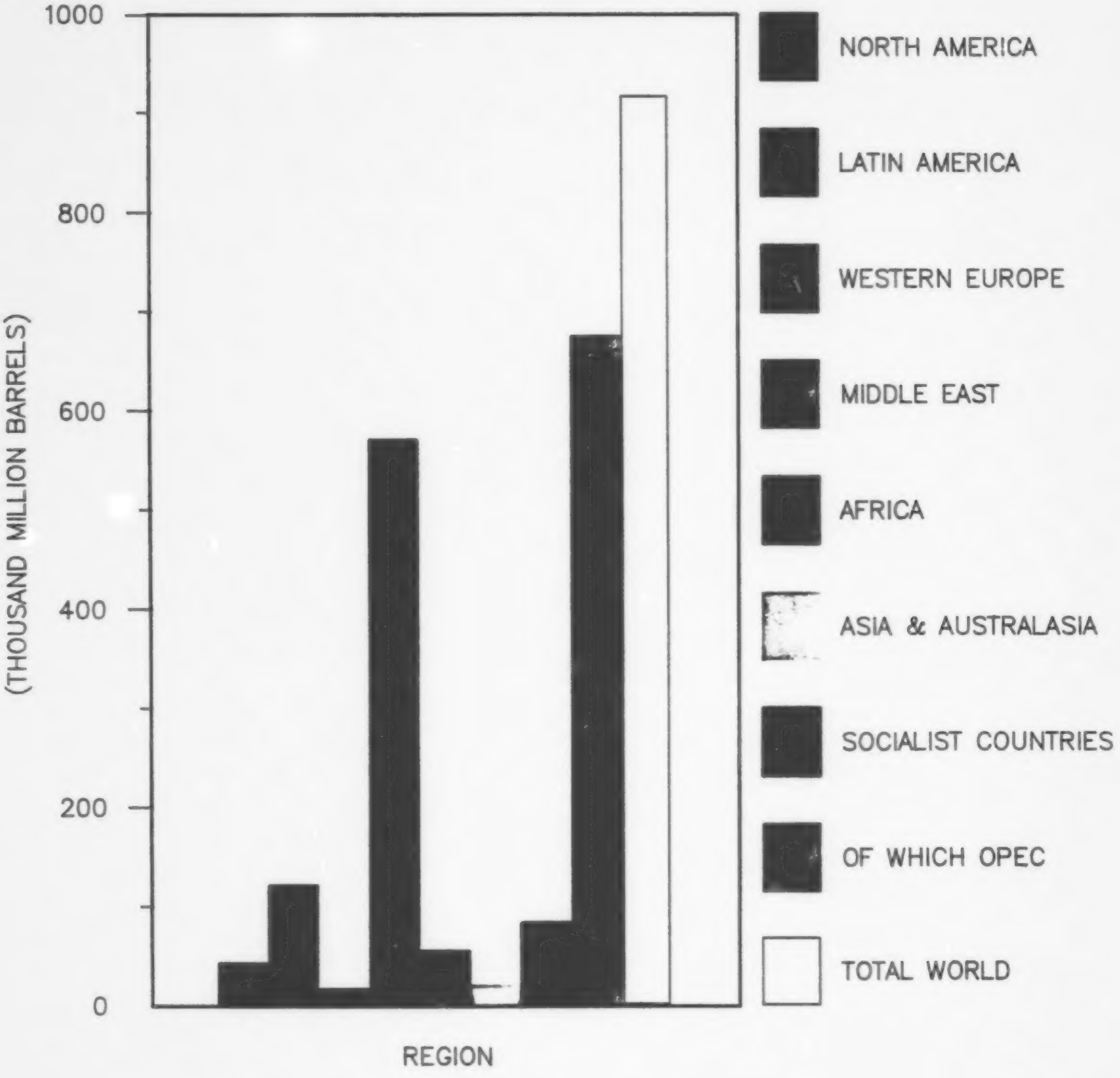
short term and current plans for an additional 5 - 9 million b/d by 1995 would have to be revised upward. The world could be in for a fourth price shock and a repeat of the events that occurred in 1979 and to lesser degree in 1973.

SUMMARY

Either way you look at it, OPEC influence and control is returning to the petroleum industry at a pace that is directly proportional to the increase in demand. Looking at OPEC's oil reserves and considering the low probability of discovering substantial non-OPEC reserves in future, it is apparent that control will remain with OPEC for the foreseeable future.

BAR CHART

PROVEN WORLD OIL RESERVES BY REGION AT END 1988



SOURCE: THE BRITISH PETROLEUM COMPANY
STATISTICAL REVIEW OF WORLD ENERGY.
JUNE 1989

SPEAKER : PATRICIA M. MOHR

COMPANY : THE BANK OF NOVA SCOTIA

LOCATION: TORONTO, ONTARIO

TOPIC : IMPROVED PROSPECTS FOR OIL IN THE 1990s

BIOGRAPHY: Ms. Mohr is Senior Economist/Manager in the Economics Department, The Bank of Nova Scotia. She is responsible for industry and commodity market analysis at the Bank and developed the Scotiabank Commodity Price Indices. Ms. Mohr is a columnist for the Pulp & Paper Journal (The Bottom Line) and maintains a close interest in international economic and financial developments.

Prior to joining Scotiabank, Ms. Mohr spent a number of years as Senior Economist with Alberta Energy Co. Ltd. in Calgary. She served as Corporate Economist for Canadian Pacific in London, England and was heavily involved in the company's tanker and bulk shipping operations. She began her career as a mineral economist with the Department of Energy, Mines and Resources in Ottawa.

Ms. Mohr was born in Vancouver, British Columbia and is a graduate of the University of British Columbia.

ABSTRACT

IMPROVED PROSPECTS FOR OIL IN THE 1990s

A number of developments have recently been moving in favor of moderately higher crude oil prices in the early 1990s. OPEC's share of western world oil consumption has increased from a low of 35 percent in 1985 to more than 40 percent last year. Though still below the 56 percent average of the late 1970s, the gain points to a tightening global supply/demand balance for crude oil.

The rising demand for OPEC oil reflects a 2.4 percent annual increase in world oil consumption since 1986, partly fuelled by booming gasoline and middle distillate sales in the Far East--especially in Singapore, South Korea and Taiwan. After a sharp decline in the early 1980s, the intensity of oil use in OECD countries also has levelled off. Little change in the inflation-adjusted price of OPEC's basket of reference crudes largely accounts for the improvement. Prospects for an economic soft landing in the United States and continuing rapid economic growth in the Far East suggest further consumption gains in the early 1990s.

Equally important, U.S. dependence on imports is increasing. In 1989, imports of crude oil and petroleum products rose to a ten year high and accounted for 44 percent of domestic consumption. While the Alaskan oil spill was partly to blame, U.S. output is on a long-term declining trend in both the lower 48 states and in Alaska.

OPEC's ability to maintain prices above US $18 per barrel by restraining output is gradually improving. Seven of thirteen OPEC countries are now producing close to full capacity and the new production-sharing formula agreed in November will provide a framework for expansion. Oil prices will probably average US $20-23 over the next several years. However, prices will remain uncertain until the demand for OPEC oil remains consistently above 23-24 million barrels per day - probably by 1992. At this point, OPEC will be producing at 75-80 percent of maximum sustainable capacity.

- - - -

This paper will further develop the following points:

1. The role of Far Eastern demand in tightening the global supply/demand balance for crude oil.
2. The impact of prices on crude oil demand and the objective of some OPEC countries to raise prices moderately without setting off a further round of conservation.
3. The impact of firmer prices of OPEC exploration and development.

Improved Prospects For Oil In The 1990s

A number of developments have recently been moving in favour of moderately higher crude oil prices in the 1990s. Eight of thirteen OPEC countries are now producing at or close to capacity. OPEC's share of Western World oil consumption also has increased from a low of 34 per cent in 1985 to around 41.5 per cent last year. Though still below the 58 per cent average of the late 1970s, the gain points to a tightening global supply/demand balance for crude oil.

The rising demand for OPEC oil reflects a 2.7 per cent annual gain in world oil consumption since 1986, partly fuelled by booming marine bunker, gasoline and aviation fuel sales in the Far East -- especially in Singapore, South Korea and Thailand. Little change in the inflation-adjusted price of oil since 1986 has slowed the decline in oil intensity of use in OECD countries. Prospects for an economic soft landing in the United States and continuing rapid economic growth in the Far East suggest further consumption gains in the early 1990s.

Equally important, U.S. dependence on imports is increasing. In 1989, imports of crude oil and petroleum products rose to a ten-year high and accounted for 46 per cent of domestic consumption. While the Alaskan oil spill was partly to blame, U.S. output is on a long-term declining trend.

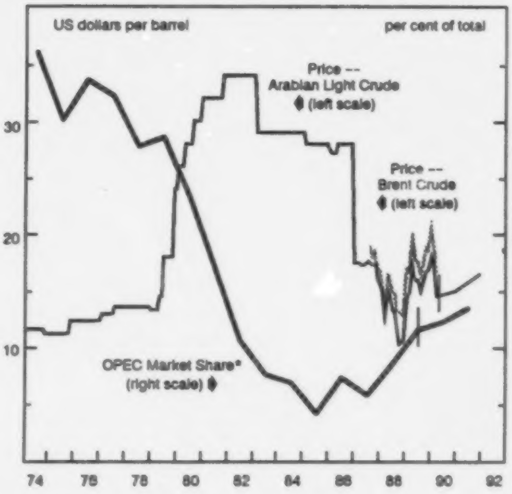
Despite these developments, oil prices will remain volatile and uncertain over the next eighteen months. OPEC production has moved well ahead of demand so far this year and renewed output restraint will be needed to keep prices at or above OPEC's US$18 target price. Not until 1992 will the call on OPEC supplies consistently exceed 23 to 24 million barrels per day (mb/d). At this point, all but three OPEC countries -- Saudi Arabia, Venezuela and Iraq -- will be able to produce close to maximum rates without causing price weakness.

Tightening OPEC Supplies

The best evidence of tightening global markets for crude oil is found in OPEC's rising capacity utilization. The demand for OPEC oil will increase this year to 80 per cent of maximum sustainable capacity. At its low point in 1985, OPEC output was only 64 per cent of capability. Though production rates have climbed ahead of demand in the first five months of this year, causing price weakness, only three countries now have significant excess supply. (See table on page 4 for further details.) Above-quota production by Saudi Arabia, Kuwait and the United Arab Emirates reflects an effort to stake out a larger market share in the early 1990s.

In addition to rising demand, the improvement in operating rates reflects a sharp drop in OPEC

OIL PRICES & OPEC MARKET SHARE



* Demand for OPEC oil divided by Western World consumption
Source: International Energy Agency, Platt's, Scotiabank estimates
| Indicates forecast period.

OPEC – MAXIMUM SUSTAINABLE PRODUCTION CAPACITY (millions of barrels per day)

	1979	1990
OPEC	**39.2**	**27.0 - 27.9**
GULF	**28.3**	**18.8 - 19.5**
Iran	7.0	3.0 - 3.5
Iraq	4.0	3.8 - 4.0
Kuwait	3.3	2.2
Saudi Arabia	10.8	7.3
UAE	2.5	2.0
Qatar	0.7	0.5
NON-GULF	**10.9**	**8.2 - 8.4**
Indonesia	1.8	1.3 - 1.4
Libya	2.5	1.4 - 1.5
Ecuador	0.2	0.4
Venezuela	2.4	2.5
Gabon	0.3	0.2
Algeria	1.2	0.6
Nigeria	2.5	1.8

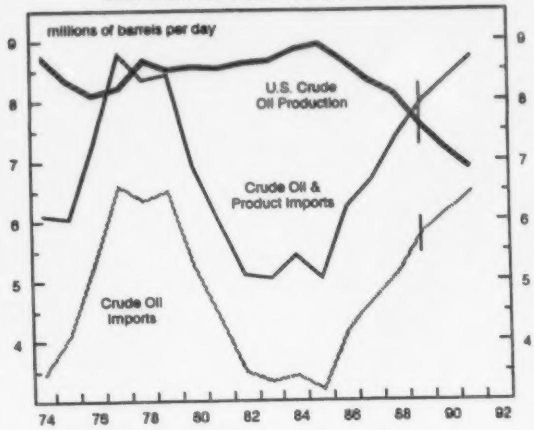
capacity from 39.2 mb/d in 1979 to only 27.0–27.9 mb/d today. Oil prices have not been high enough to encourage the investment needed to maintain reserves.

Rising U.S. Oil Imports

Though U.S. petroleum consumption has only recently returned to early 1980 levels, imports have increased substantially in the past several years and now account for close to 50 per cent of consumption. In the first three months of 1990, U.S. petroleum imports rose to almost 8.5 mb/d -- a 3.5 mb/d gain over the low in 1985. OPEC captured all of the first quarter rise with Saudi Arabia, Venezuela, Nigeria and Iraq being the four largest suppliers among the cartel.

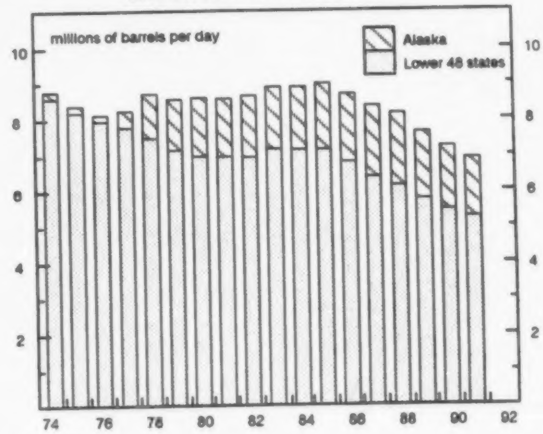
The jump in U.S. imports reflects a plunge in U.S. crude oil reserves and output. In the mid-1980s, increasing Alaskan supplies offset lower production in the lower 48 states. However, Alaskan output peaked in 1988 and is expected to fall by around 100,000 b/d annually over the next ten years. Alaska will become a marginal producing area by the year 2010, unless unforeseen new developments offset the drop from the giant Prudhoe Bay field. Alaska accounted for 25 per cent of U.S. output last year.

U.S. OIL PRODUCTION & IMPORTS



- Historical data from U.S. Department of Energy.
| Indicates forecast period.

U.S. CRUDE OIL PRODUCTION



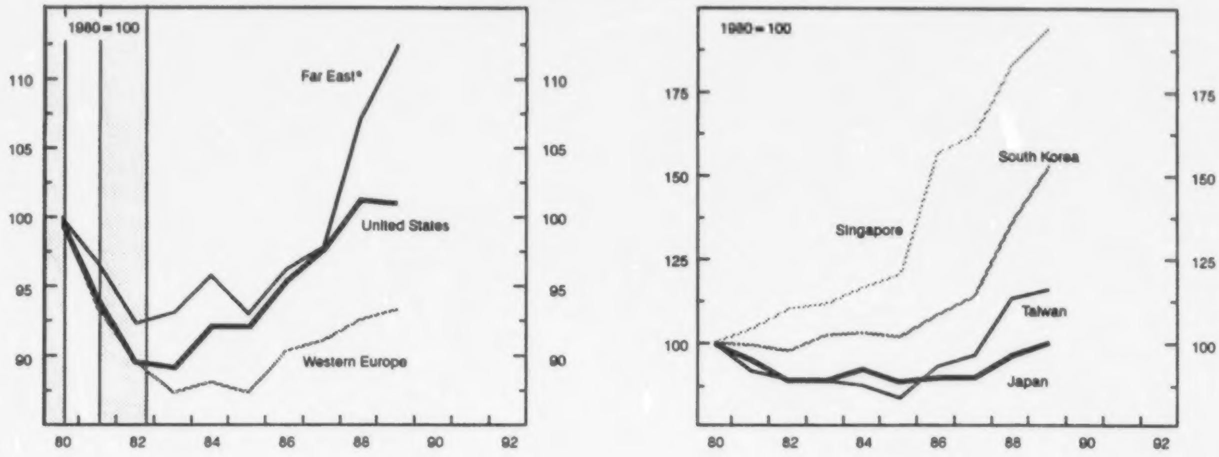
1990–91 Scotiabank estimates.

In the lower 48 states, an expected pick-up in oil drilling and reserves in the early 1990s will probably be restrained by limited prospects for exploration success and a shift in exploration effort towards natural gas. Environmental constraints will prevent further offshore development in California.

Buoyant Far Eastern Demand

Oil consumption has advanced by around 5 per cent per annum since 1985 in seven key Far Eastern countries (Japan, Indonesia, Malaysia, Singapore, South Korea, Taiwan and Thailand), raising their share of Western World consumption to 14 per cent. The average annual percentage gains have been most rapid in Singapore (12.7), South Korea (10.7)

PETROLEUM CONSUMPTION



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* Japan, Indonesia, Malaysia, Singapore, South Korea, Taiwan and Thailand.
- Shaded areas indicate U.S. recession periods.

and Thailand (9.4). Though oil intensity of use peaked in most Southeast Asian countries in the early 1980s, intensity recently has picked up again in several areas.

A Gradual Recovery in Oil Prices

Oil prices are expected to move slowly higher in the early 1990s alongside a tightening global supply/demand balance -- particularly for light/sweet grades. OPEC's excess capacity is concentrated in the heavier/sourer grades found in Saudi Arabia and Venezuela. Nevertheless, the extent of price improvement will be limited by two factors. First, above-quota production by Saudi Arabia and Kuwait earlier this year seems to indicate a policy of delaying or limiting the price increase. Only a moderate gain in oil prices will sustain growth in world demand and will discourage development of higher-cost reserves by non-OPEC producers. Second, OPEC members are already planning to expand their capacity to meet higher global oil demand in the 1990s. A recent report estimates OPEC capability at 31.5 mb/d by 1992 and over 33 mb/d by 1995. Though these estimates are probably high, some increase is likely.

The marketing arrangements and the specific quality of Hibernia crude oil are uncertain. However, it seems reasonable to use dated Brent oil as a price indicator for Hibernia. Industry sources indicate that Hibernia oil will probably average 32-34°API, will have a sulphur content of 0.4 to 0.6 of one per cent and will be a waxy crude. A small price discount to Brent oil is probable.

OIL PRICE OUTLOOK
(annual average, U.S. dollars per barrel)

	1986	1987	1988	1989	------1990------		1991F
					Q1	Annual F	
Brent (37°API, dated)	--	18.19*	15.02	18.24	19.80	16.5 - 18.5	17.5 - 20.5
West Texas Intermediate (40°API)	14.58	19.20	15.96	19.63	21.77	18 - 20	19 - 22

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* Average from August to December 1987.

OIL SUPPLY AND DEMAND BALANCE -- WESTERN WORLD
(millions of barrels per day)

	1986	1987	1988	1989	1990F	1991F
World Oil Consumption	48.3	49.4	51.2	52.3	52.9	54.1
Non-OPEC Supply*	28.5	29.1	29.4	28.7	28.7	28.7
United States	10.3	10.0	9.8	9.2	8.8	8.4
Canada	1.8	1.9	2.0	2.0	1.9	1.9
North Sea	3.7	3.8	3.7	3.7	3.8	3.9
To (From) Inventories	0.0	(0.7)	(0.2)	0.0	0.1	0.0
OPEC NGLs and Condensate	1.8	1.8	1.8	1.9	1.9	1.9
Demand for OPEC Oil	18.0	17.7	19.7	21.7	22.4	23.5
OPEC's Market share**	37.3	35.8	38.5	41.5	42.3	43.4

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* Includes processing gain and natural gas liquids.
** OPEC's market share was 53 per cent in 1980 and the price of Arabian Light was $28.50.
*** Source: International Energy Agency, Scotiabank estimates.

OPEC CRUDE OIL RESERVES & PRODUCTION CAPACITY

	Proved Reserves	Production January-May 1990*	Maximum Sustainable Production Capacity in 1990**	Capacity Utilization in 1990***
	(billions of barrels)	------(millions of barrels per day)------		(per cent)
OPEC	767.0	23.47	27.0 -27.9	84.1
GULF	650.1	16.00	18.8 - 19.5	82.1
Iran	92.9	2.92	3.0 - 3.5	83.4
Iraq	100.0	2.95	3.8 - 4.0	73.8
Kuwait	94.5	2.02	2.2	91.8
Saudi Arabia	254.9	5.72	7.3	78.4
UAE	98.1	2.00	2.0	100.0
Qatar	4.5	0.39	0.5	78.0
Neutral Zone	5.2	Divided equally between Saudi Arabia and Kuwait		
NON-GULF	116.9	7.47	8.2 - 8.4	88.9
Indonesia	8.2	1.17	1.3 - 1.4	83.6
Libya	22.8	1.27	1.4 - 1.5	84.7
Ecuador	1.5	0.28	0.4	70.0
Venezuela	58.5	2.01	2.5	80.4
Gabon	0.7	0.27	0.2	Production above capacity
Algeria	9.2	0.75	0.6	
Nigeria	16.0	1.72	1.8	95.6

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* OPEC's quota (22 million barrels per day) is lower than current output.
** Source: East-West Center, Resource Systems Institute.
*** OPEC production from January to May 1990 divided by maximum sustainable production capacity.

While the information in this report is from sources believed to be reliable, neither the information nor the analysis shall be taken as a representation for which the Bank or its employees incur any responsibility.

SPEAKER : BARRY RODGERS

COMPANY : DEPARTMENT OF MINES AND ENERGY
GOVERNMENT OF NEWFOUNDLAND AND LABRADOR

LOCATION: ST. JOHN'S, NEWFOUNDLAND

TOPIC : THE EFFECTS OF OIL PRICE, INFLATION, INTEREST RATES AND CURRENCY EXCHANGE RATES ON OFFSHORE PROJECT VIABILITY

BIOGRAPHY: Mr. Rodgers graduated from Memorial University in 1978 with concentrations in economics and mathematics. After a year with the Newfoundland Telephone Company, he started with the Government of Newfoundland and Labrador in the former Petroleum Directorate - now the Department of Mines and Energy.

Since joining government in 1980, Mr. Rodgers has held several positions in the areas of economic and financial analysis and has served in a technical support role to the Hibernia negotiations process. Currently, Mr. Rodgers holds the position of Director, Financial Analysis where he is responsible for financial, industrial and employment benefits analysis of both offshore and onshore energy developments.

ABSTRACT

THE EFFECTS OF OIL PRICE, INFLATION, INTEREST RATES, AND CURRENCY EXCHANGE RATES ON OFFSHORE PROJECT VIABILITY

In order to illustrate the effects of interest rates, oil prices, inflation and currency exchange on the economic viability of offshore projects, the presentation will focus on the Terra Nova field.

Analysis will be conducted on the basis of both Burdened and Unburdened economics (Government and No Government) and will incorporate a range of interest rate, oil price, inflation and currency exchange rate estimates.

To place these estimates in perspective the total volume of oil expected to be recovered (field size) and the shape of the production profile will also be studied.

The criteria to be employed in making the various comparisons will result from a detailed financial cashflow analysis and will include rate of return, net present value and years to payback.

The medium for presentation purposes will be slides and speaking notes.

To assess the effects of changes in crude oil price, inflation rates, interest rates, and currency exchange rates on offshore project viability the following two basic questions must first be answered:

1. Which specific project is in question; and,

2. What assessment criteria will be employed.

The question of which project is important because, other than directional effects, the impacts measured, and conclusions drawn, will depend very much on the specific project under study. For example, a project generating a minimum acceptable rate of return of, say, 15.5 percent would not be able to sustain any price decrease or cost increase whereas a field with a 20 or 30 percent rate of return could sustain rather large price decreases or cost increases.

Since Terra Nova will likely be the next of Newfoundland's oil fields to be developed, this assessment takes it as a base for analysis and comparison. In addition, the effects on the minimum 'stand alone' economically viable reserves size in the Newfoundland offshore are also assessed.

The selected measure of project viability is Net Present Value (NPV) at a 10 percent real discount rate. At an assumed long run average inflation rate of 5 percent, this represents a minimum acceptable rate of return of 15.5 percent. This is consistent with the North Sea experience and with that resulting from the Hibernia negotiations process. As long as NPV at 10% real is greater than or equal to zero, the project is considered economically viable. This NPV criteria is applied to both the Terra Nova analysis and to the minimum field size analysis. Terra Nova will be discussed first.

All analyses are presented in terms of a variation around a base case. The Terra Nova base case economic and fiscal parameters are presented in Tables 1 and 2. With respect to the economic parameters of Table 1, the following are the most noteworthy:

1. price at $20 US ($24.39 Cdn.) real 1990 per barrel;

2. recoverable reserves at 400 million barrels;

3. capital costs at $3.7 billion real 1990 Canadian; and,

4. operating costs at $2.0 billion real 1990 Canadian.

The recoverable reserves figure of 400 million barrels represents the 406 million barrels estimate presented by the Canada-Newfoundland Offshore Petroleum Board in its "Annual Report 1988-1989". Capital and operating costs were developed entirely by the author. They do not necessarily represent the views of the Newfoundland Department of Mines and Energy and are independent of those that may be developed by the project owners.

In considering these assumptions, especially those related to capital and operating costs, it should be noted that facility design work for Terra Nova is in the very preliminary stages. This, plus the fact that reservoir simulation work is still ongoing, makes cost estimation extremely difficult and the correlation of costs and recoverable reserves even more difficult. The cost estimates employed here are only one possible set that can reasonably be associated with a recoverable reserves estimate of 400 million barrels. Optimization work could show that recoverable reserves can be increased significantly without a corresponding increase in costs. Also, new technologies such as floating production facilities with concrete as opposed to steel hulls, offer the potential for cost decreases and daily production volume increases. The detailed studies required to answer questions such as these are only now beginning. At this point in time, we must bear in mind that the recoverable reserve estimate is placed in a range as wide as 200-650+ million barrels and that recoverable reserves are significantly more important in assessing project economics than costs.

The necessary fiscal and benefits negotiations between field owners and governments have not yet taken place. This analysis assumes, by way of example, fiscal terms similar to those employed for Hibernia and described in "Statement of Principles Hibernia Development Project", July 1988. This should in no way be taken as an indication of Governments' official position with respect to this matter.

Table 2 shows the assumed basic fiscal parameters to include:

1. normal corporate income tax rules;
2. retail sales tax at a rate of 12 percent; and,
3. royalty comprised of three parts:
    A. Gross at 5%
    B. Net at 30%
    C. Supplementary at 12.5%.

Note that government assistance such as grants, loan guarantees, sales tax relief or a graduating of the Gross royalty is not required.

The results flowing from the economic and fiscal assumptions described above are presented in Table 3. This table shows that, at 20.6 percent, the after-tax project rate of return is 33 percent (20.6/15.5 = 1.33) higher than the minimum required and that the minimum break-even price (supply price) is $16.76 (U.S.) compared to present levels of $18.24 (U.S.) to $22.41 (U.S.) and our assumed long term average of $20 (U.S.).

It is noted that the costs upon which these results are based include a 25 percent contingency factor. If this contingency proves not to be necessary, then the rate of return would likely rise to in excess of 26 percent. If at the same time price was to increase to $25 (U.S.) per barrel, then this rate of return would be pushed even higher to approximately 32 percent. For these reasons, and because reservoir simulations show that at 400 million barrels the field is capable of producing in excess of the assumed peak of 100,000 barrels per day, the results presented here are viewed as conservative.

With the results of Table 3 as a point of reference, the subject parameters are discussed next. These are dealt with in the following order:

1. CRUDE OIL PRICE (P);
2. CAPITAL COSTS (CC);
3. OPERATING COSTS (OC);
4. U.S. TO CANADIAN EXCHANGE RATES (ER);
5. BORROWING RATE (BR); and,
6. INFLATION (IN).

Originally this paper did not intend to deal with capital or operating cost sensitivities. However, since these parameters have a similar or greater impact on project profitability than either exchange rate, borrowing rate or inflation and since their inclusion permits the assessment of cost changes other than those associated with inflation (those associated with real dollar escalation above inflation), they are now included.

Before starting the discussion of each specific parameter, Figures 1 and 2 are presented in order to rank and to show the relative impacts of each. It is noted that the changes in each parameter are assumed not to affect the other parameters. This assumption is necessary in order to isolate the effects of each.

Figure 1 presents the effect on NPV of equal percentage changes in each of price, capital costs and operating costs and indicates the base case NPV line along with the dashed break-even line. The base case is represented by the zero percentage change point along the horizontal axis and by the point where all sensitivity lines intersect. With the slope of the NPV line as an indicator, Figure 1 shows clearly that price is the most significant variable in assessing project viability: Capital cost follows; and then, operating cost. Because the distinction between the impacts of changes in operating costs, borrowing rate and inflation is so small, it is not feasible to show these lines in Figure 1. Retaining the capital cost line as a point of reference, the relative impacts of these parameters, plus the exchange rate parameter, are presented in Figure 2.

The exchange rate line shows its importance to be similar to that of capital costs. This is due to the range selected. A range of -9 percent to +10 percent (.75 to .90), while reasonable for exchange rate, is not realistic for costs. Since the percentage change in costs (both capital and operating) is likely to be far greater than that in exchange rate, costs should be considered the more significant parameter.

There is normally a very high correlation between inflation rate and borrowing rate. Following the separate discussions of borrowing rate and inflation rate below, the combined effects of changes in both are shown by considering inflation rate changes from 5 percent to 10 percent and by assuming that the spread between borrowing rate and inflation is held constant at 5 percentage points.

1. CRUDE OIL PRICE

The most difficult parameter to predict is probably crude oil price. Table 4 shows that over the past 10 years the Saudi Bench price has declined from just under $49 (U.S.) per barrel to its present level of approximately $17.50 (U.S.) per barrel. Combined with its graphical illustration in Figure 3, this table shows that since 1988 spot prices have been trending upward to their present level in the $18 to $22 (U.S.) range.

Figure 4 and the associated Table 5 shows the effects of price changes from $15 to $40 (U.S.) (-25% to +100%) on project Net Present Value (NPV) and other selected profitability indicators. Using the price/NPV line of Figure 4 as a reference for discussion, the following points respecting the impact of crude oil price on offshore project viability are noted:

1. Slope changes in the price/NPV line are due to the profit sensitive nature of the assumed fiscal package;
2. In a positive direction, NPV is increasing at a decreasing rate because Net and Supplementary royalties are being activated, thus taking an increasing share of project revenues;
3. In a negative direction, the slope of the price/NPV line increases because of the relative weight of project costs versus revenue and because the fixed 5%

Gross royalty becomes more significant as project rate of return decreases; and,

4. Price could decline by approximately 17 percent to $16.76 (U.S.) before project viability is threatened. This is shown by comparing the percentage change below zero along the horizontal axis with the point at which the price/NPV line crosses the break-even line.

2. CAPITAL COSTS

Figure 5 with an associated Table 6, shows the effects on Terra Nova project profitability of -50 percent to +25 percent changes in capital costs. Note the following points from Figure 5:

1. As with price, slope changes in the capital cost/NPV line are attributable to the profit sensitive nature of the assumed fiscal regime;

2. The increased slope of this line as costs increase (profitability decreases) is again due to the relative weight of project costs versus revenue and to the fixed 5% Gross royalty becoming more significant; and,

3. Capital costs could increase in excess of 25 percent before the break-even line is reached. This is especially significant when one remembers that costs already include a 25 percent uplift for contingency.

3. OPERATING COSTS

Figure 6 and Table 7 deal with the effects of operating cost changes. Focusing on NPV, they show that:

1. The relationship between NPV and operating cost is basically linear. It is noted, however, that for large operating cost increases, the relative weight of costs and the fixed Gross royalty cause the slope of the operating cost/NPV line to increase; and,

2. For operating cost increases of 25 percent, NPV does not even approach the break-even point.

We estimate that operating costs could increase by 75-80 percent before the project is placed in jeopardy.

4. EXCHANGE RATES

Unlike price and costs, exchange rate affects both the revenue and cost sides of the profitability equation. It is the effect that exchange rate has on price that most accounts for its relative importance as a sensitivity parameter. To illustrate, Table 8 presents the difference in Canadian dollar equivalent price and costs for exchange rates of .75 to .90. This table shows that for a 20 percent change in exchange rate from .75 to .90, price is decreased by 16.7 percent while capital and operating costs are decreased only by 9.5 percent and 5.1 percent respectively. For a project developer, the ideal situation would be to experience high Canadian to US exchange rates when expending funds and low rates when selling production.

The effects of exchange rate changes on selected profitability indicators are presented in Table 9. The comparison of base case and break-even NPV results is presented in Figure 7. The following three points are noted:

1. Like that with operating costs, the exchange rate/NPV line is basically linear over the range selected;

2. Project economics benefit as Canadian to U.S. exchange rate decreases; and,

3. Exchange rate changes will not threaten Terra Nova project viability.

5. BORROWING RATES

Through Figure 8 and Table 10, this section shows the effects on Terra Nova project viability of interest rate changes from 8% to 15%. Figure 8 illustrates that:

1. The borrowing rate/NPV line is linear; and,

2. Interest rate changes will not likely threaten Terra Nova project viability.

6. INFLATION RATES

One might expect that applying inflation equally to both price and costs would not alter the real (net of inflation) dollar value of the project and thus would not impact on project viability. After all, if one adjusts for inflation (no matter what its rate), should not the real dollar revenues and costs remain unchanged? The answer to this question would be affirmative if not for inflation's impact on corporate income tax, royalty payout, and loan repayment. Changes in corporate income taxes payable result from the associated Capital Cost Allowance (CCA) and Canadian Development Expense (CDE) calculations and from changes in interest expense deductions caused by changes in the loan repayment date. Representing depreciation, CCA and CDE are calculated only in nominal dollar terms; that is, they are not indexed to inflation. For this reason, as inflation increases the differential between revenues and costs grows larger causing an increase in taxes payable and a resultant decrease in net cash flow. This differential between revenues and costs also helps loan repayment as project sponsors benefit from the reduced interest charges as a result of loans being repaid faster with inflated dollars. This occurs because loan repayment is assumed to be a fixed percentage of project net revenue. Some of the benefits of earlier loan repayment are offset by increased corporate income tax payments resulting from reduced interest expenses. With respect to royalty payout, inflation increases cause cumulative revenue to overtake cumulative costs earlier, thus leading to increased royalty payments.

The net results of inflation rate changes are shown in Table 11 and its associated Figure 9. Referring to Figure 9, note only that:

1. Inflation rate changes, by themselves, will not likely threaten project viability.

7. COMBINATION - INFLATION RATE & BORROWING RATE

It is important to reiterate that many of the parameters discussed above and presented as moving in isolation of each other do in fact move together. This is especially true of inflation rate and borrowing rate, since the borrowing rate contains a component for inflation. The impact of inflation can be further estimated by assuming a constant spread between the two rates and by assessing them both in combination. This is accomplished in Figure 10 by illustrating the effects on NPV of increases in inflation rate, borrowing rate and a combination of the two. Note that the scale on this figure is much narrower than that on previous figures and runs only from the Base Case NPV of 270.8 to the break-even value of zero.

Figure 10 shows that, when considered in isolation, borrowing rate and inflation rate changes translate into basically equal effects on project NPV. Considering the combined effect of these two parameters as representing inflation, we see that inflation is the much more significant variable. In fact, judging by the area above either the inflation rate or the borrowing rate line compared to that above the combined line, we see that inflation has approximately double the effect on project NPV that borrowing rate has. Given that the selected extremes of 10 percent and 15 percent for inflation and borrowing rate respectively are not that remote, it seems reasonable to conclude that inflation has a very significant impact on project viability. Terra Nova project viability, however, is still not threatened.

MINIMUM ECONOMICALLY VIABLE RESERVES SIZE

- Offshore Newfoundland -

Having presented the effects of price, costs, exchange rate, borrowing rate and inflation on Terra Nova project economics, attention is now focused on the impacts of changes in these parameters on the minimum economically viable reserve size. This is facilitated through Table 12. As one would expect, price increases or cost decreases push the minimum reserve size downward. The reverse is true for price decreases or cost increases.

The one point I wish to note respecting Table 12 is that:

1. the minimum 'stand alone' economically viable reserve size is placed in the 100 to 200 million barrels range with the most likely estimate being 150 million barrels.

CONCLUSION

This paper has presented an assessment of the likely impacts of changes in (1) crude oil price, (2) capital costs, (3) operating costs, (4) U.S. to Canadian currency exchange rate, (5) borrowing rate, and (6) inflation on the economic viability of the Terra Nova project. It has also estimated the impacts of these parameters on the minimum recoverable reserve size that is economically viable in the Hibernia/Terra Nova area of the Newfoundland offshore. Its major conclusions are:

1. With the cost contingencies assumed, it seems that price is the only variable that can reasonably be considered as a threat to Terra Nova project viability at this time;

2. With expected likely price increases and cost decreases, the Terra Nova base case results shown here are viewed as conservative. Rather than being in the 20 percent to 21 percent range, rate of return is more likely to be in the range of 26 percent to 32 percent; and,

3. The minimum economically viable recoverable reserve size for the Newfoundland Offshore is placed in the 100 to 200 million barrels range with the most likely estimate being put at 150 million barrels. The base case Terra Nova recoverable reserves estimate of 400 million barrels employed here exceeds this minimum estimate by 167 percent!

TABLE 1.

TERRA NOVA PROJECT

BASE CASE ASSUMPTIONS - ECONOMIC TERMS

PARAMETER	VALUE
PRICE (average)	$20 US 1990
RECOVERABLE RESERVES	400 MMBbls
PEAK PRODUCTION	36.5 MMBbls
PRODUCTION LIFE	15 YEARS
CAPITAL COSTS	$3,689 MILLION CDN.
OPERATING COSTS	$2,000 MILLION CDN.
CDN TO US EXCHANGE RATE	0.82
BORROWING RATE	10.00%
DEBT/EQUITY RATIO	40/60
INFLATION RATE	5.00%
DISCOUNT RATE	10.00% REAL

SOURCE: NFLD. DEPT. OF MINES AND ENERGY

TABLE 2.

TERRA NOVA PROJECT

BASE CASE ASSUMPTIONS - FISCAL TERMS

1. NORMAL CORPORATE INCOME TAX RULES

FEDERAL RATE	28.84%
PROVINCIAL RATE (AVERAGE)	15.50%

2. ROYALTY

BASIC	
GROSS (FROM PRODUCTION START)	5.00%
NET (@ 15% RETURN)	30.00%
SUPPLEMENTARY (@ 23% RETURN)	12.50%

3. RETAIL SALES TAX

CAPITAL PHASE	12.00%
OPERATING PHASE	12.00%

4. NO GOVERNMENT ASSISTANCE REQUIRED

SOURCE: NFLD. DEPT. OF MINES AND ENERGY

TABLE 3.

TERRA NOVA PROJECT

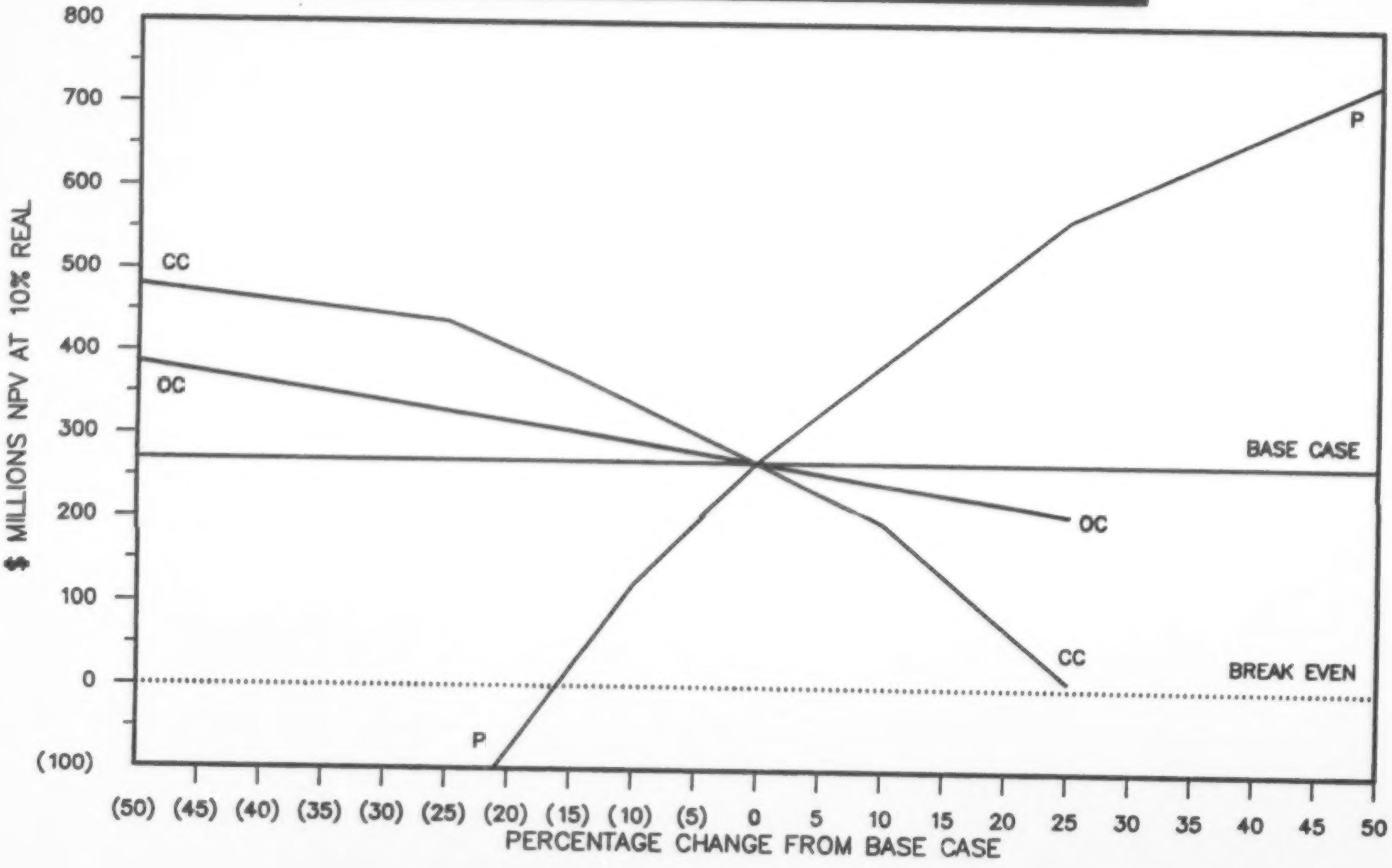
BASE CASE ECONOMIC RESULTS

	$ MILLIONS CANADIAN			
YEARS TO PAYBACK	NET CASH FLOW ($ REAL 1990)	NET PRESENT VALUE (AT 10% REAL)	NOMINAL RATE OF RETURN	SUPPLY PRICE ($ US. 1990/Bbl)
6	2079.4	270.8	20.6%	16.76

SOURCE: NFLD. DEPT. OF MINES AND ENERGY

FIGURE 1

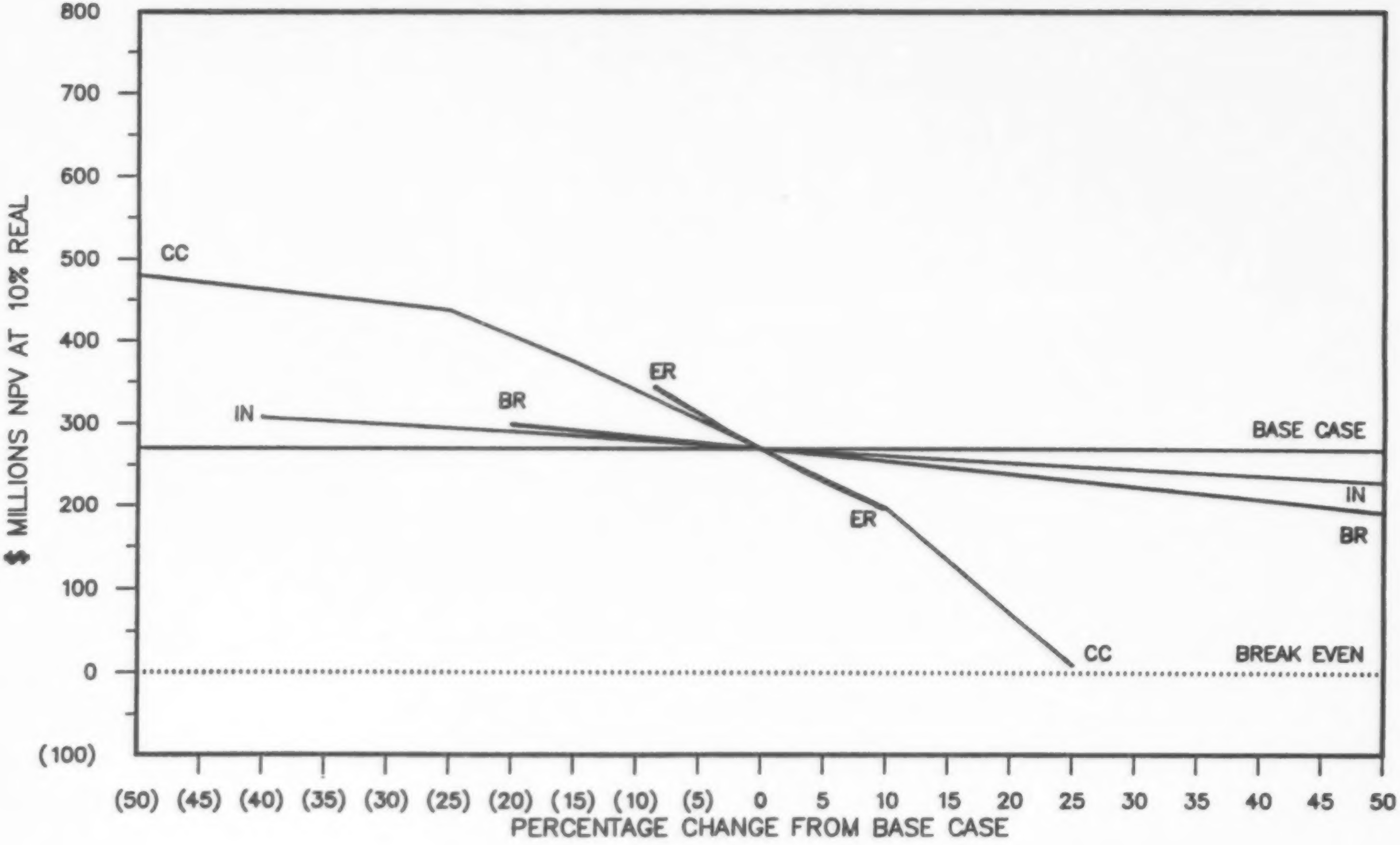
TERRA NOVA PROJECT
SENSITIVITY ANALYSIS RESULTS
CRUDE OIL PRICE, CAPITAL COSTS & OPERATING COSTS



SOURCE: NFLD. DEPT. OF MINES AND ENERGY

FIGURE 2

TERRA NOVA PROJECT
SENSITIVITY ANALYSIS RESULTS
CAPITAL COSTS, BORROWING RATE, EXCHANGE RATE & INFLATION RATE



SOURCE: NFLD. DEPT. OF MINES AND ENERGY

TABLE 4.

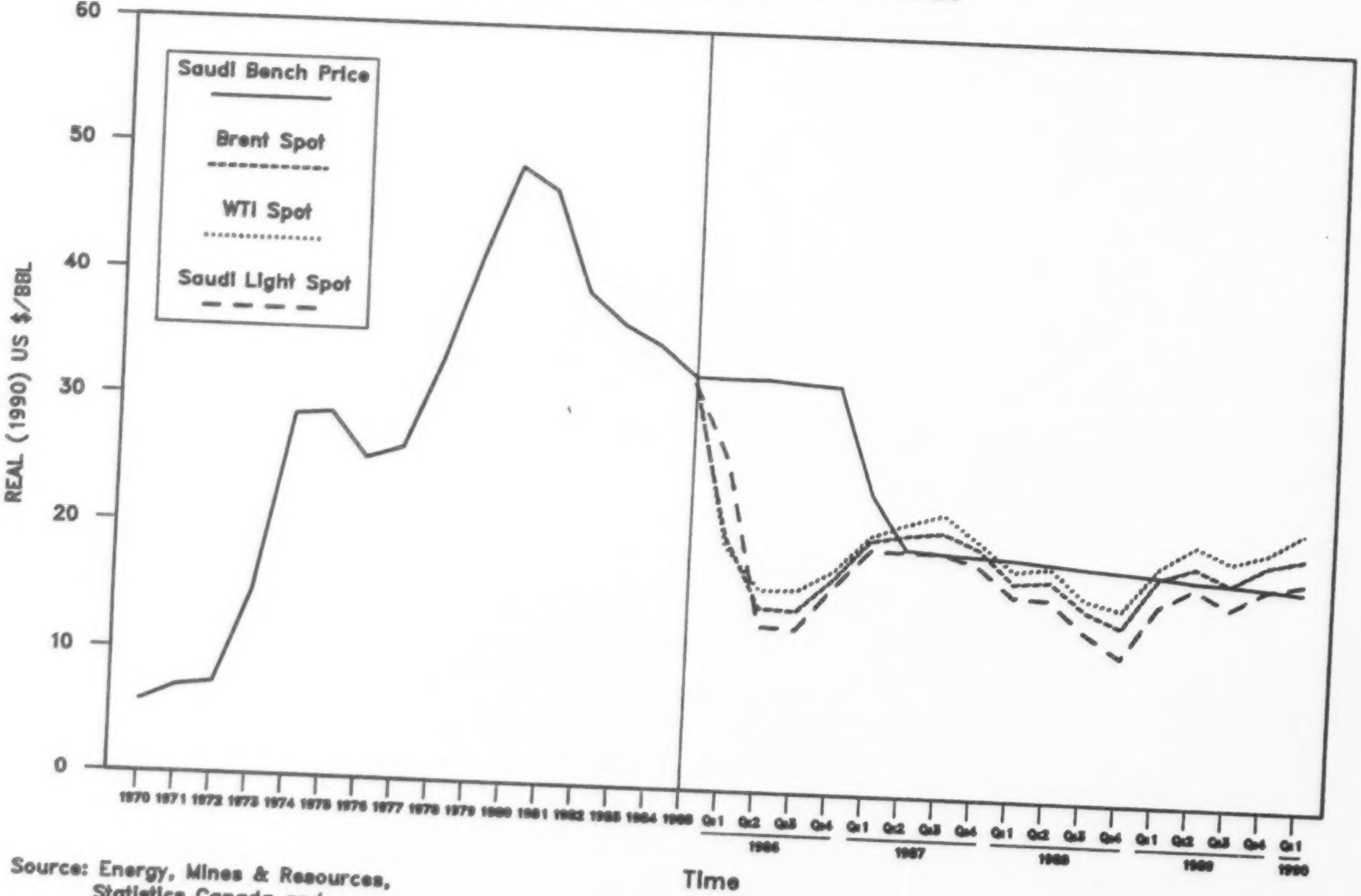
HISTORIC WORLD CRUDE OIL PRICES
REAL 1990 US $/Bbl

YEAR		SAUDI BENCH	BRENT SPOT	WTI SPOT	SAUDI SPOT
1970		5.83			
1971		7.11			
1972		7.46			
1973		14.67			
1974		28.73			
1975		28.98			
1976		25.46			
1977		26.38			
1978		33.18			
1979		41.59			
1980		48.86			
1981		47.02			
1982		39.11			
1983		36.63			
1984		35.12			
1985		32.73	32.25	32.81	32.19
1986	1	32.67	20.29	19.52	26.31
	2	32.73	14.69	16.10	13.30
	3	32.50	14.58	16.19	13.14
	4	32.34	17.20	17.82	16.53
1987	1	24.00	20.39	20.78	19.61
	2	19.76	20.92	21.85	19.60
	3	19.54	21.25	22.72	19.57
	4	19.39	20.03	20.60	18.66
1988	1	19.27	17.40	18.37	16.30
	2	19.03	17.65	18.75	16.17
	3	18.78	15.42	16.30	13.73
	4	18.60	14.24	15.63	11.94
1989	1	18.39	18.29	19.19	15.99
	2	18.10	19.27	21.00	17.56
	3	17.98	18.01	19.75	16.07
	4	17.78	19.63	20.63	17.70
1990	1	17.52	20.30	22.41	18.24

SOURCE: NFLD. DEPT. OF MINES AND ENERGY

FIGURE 3

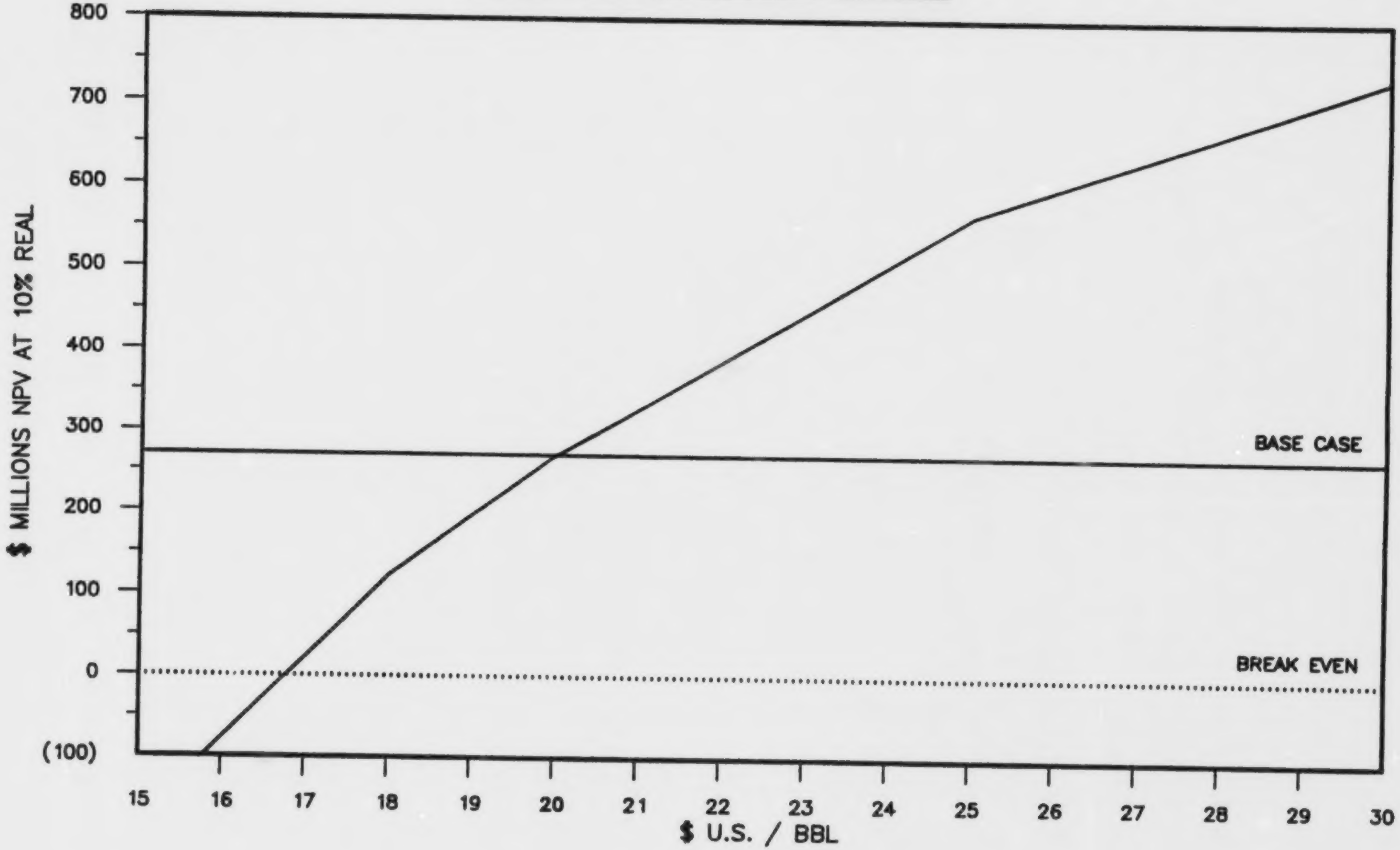
HISTORIC WORLD CRUDE OIL PRICES



Source: Energy, Mines & Resources,
Statistics Canada and
NFLD. Dept of Mines & Energy

FIGURE 4

TERRA NOVA PROJECT
SENSITIVITY ANALYSIS RESULTS
CRUDE OIL PRICE



SOURCE: NFLD. DEPT. OF MINES AND ENERGY

TABLE 5.

TERRA NOVA PROJECT

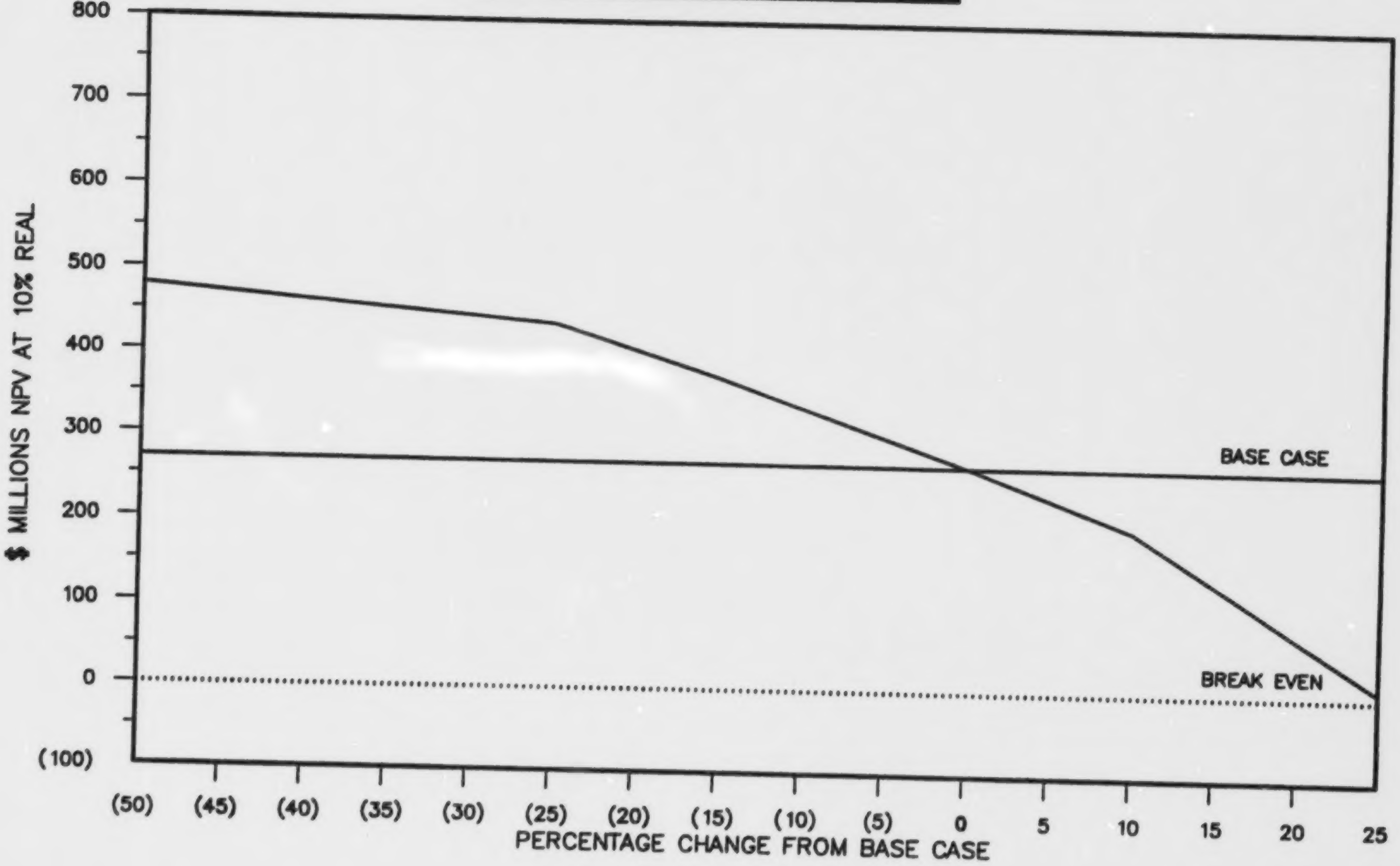
SENSITIVITY ANALYSIS RESULTS
CRUDE OIL PRICE

		$ MILLIONS CANADIAN		RATE OF RETURN (REAL TERMS)		
CASE	YEARS TO PAYBACK	NET CASH FLOW ($ REAL 1990)	NET PRESENT VALUE (AT 10% REAL)	TOTAL CAPITAL	EQUITY	SUPPLY PRICE ($ US. 1990/Bbl)
$15 U.S./BBL	9	859.6	−177.8	6.3	6.6	NA
$18 U.S./BBL	7	1764.3	124.3	10.1	12.2	NA
$20 U.S./BBL (BASE CASE)	6	2079.4	270.8	11.9	14.8	16.76
$25 U.S./BBL	4	2814.4	566.7	15.5	20.0	NA
$30 U.S./BBL	4	3104.9	734.2	17.9	23.3	NA
$40 U.S./BBL	3	4040.4	1082.7	22.4	29.1	NA

SOURCE: NFLD. DEPT. OF MINES AND ENERGY

FIGURE 5

TERRA NOVA PROJECT
SENSITIVITY ANALYSIS RESULTS
CAPITAL COSTS



SOURCE: NFLD. DEPT. OF MINES AND ENERGY

TABLE 6.

TERRA NOVA PROJECT

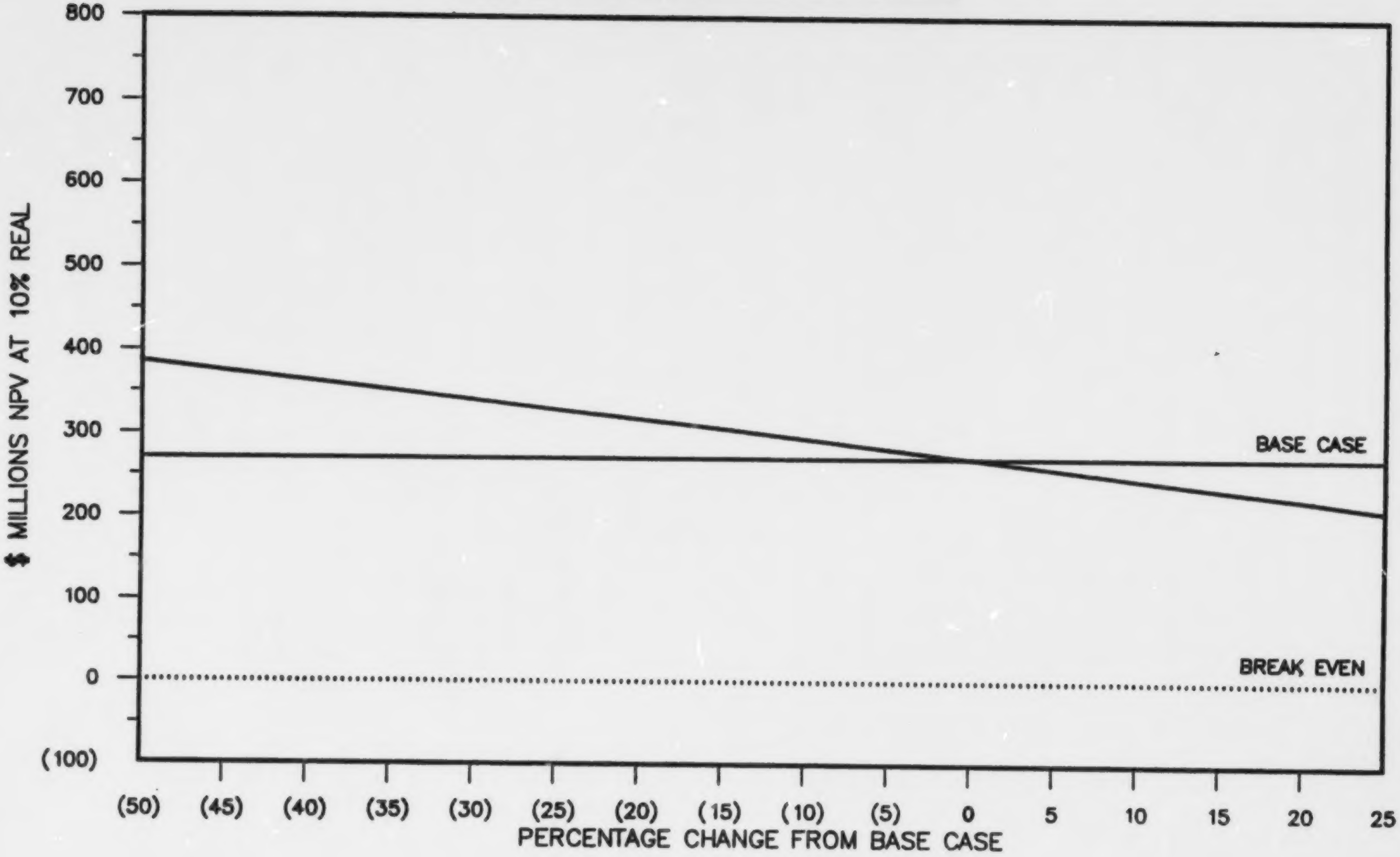
SENSITIVITY ANALYSIS RESULTS
CAPITAL COSTS

CASE	YEARS TO PAYBACK	$ MILLIONS CANADIAN		RATE OF RETURN (REAL TERMS)		SUPPLY PRICE ($ US. 1990/Bbl)
		NET CASH FLOW ($ REAL 1990)	NET PRESENT VALUE (AT 10% REAL)	TOTAL CAPITAL	EQUITY	
50% CAPITAL	3	1846.4	480.8	20.9	27.2	10.48
75% CAPITAL	4	2144.9	437.8	15.7	20.3	13.62
85% CAPITAL	5	2100.5	375.3	13.9	17.9	14.88
CAPITAL COST (BASE CASE)	6	2079.4	270.8	11.9	14.8	16.76
110% CAPITAL	6	2133.6	198.1	10.8	13.1	18.02
120% CAPITAL	7	1899.2	73.4	9.4	11.1	19.27
125% CAPITAL	7	1782.1	10.2	8.7	10.2	19.90

SOURCE: NFLD. DEPT. OF MINES AND ENERGY

FIGURE 6

TERRA NOVA PROJECT
SENSITIVITY ANALYSIS RESULTS
OPERATING COSTS



SOURCE: NFLD. DEPT. OF MINES AND ENERGY

TABLE 7.

TERRA NOVA PROJECT

SENSITIVITY ANALYSIS RESULTS
OPERATING COSTS

		$ MILLIONS CANADIAN		RATE OF RETURN (REAL TERMS)		
CASE	YEARS TO PAYBACK	NET CASH FLOW ($ REAL 1990)	NET PRESENT VALUE (AT 10% REAL)	TOTAL CAPITAL	EQUITY	SUPPLY PRICE ($ US. 1990/Bbl)
50% OPERATING	5	2337.5	386.9	13.3	17.0	14.66
75% OPERATING	5	2199.4	329.3	12.6	15.9	15.71
85% OPERATING	6	2155.4	307.4	12.3	15.5	16.13
OPERATING COST (BASE CASE)	6	2079.4	270.8	11.9	14.8	16.76
110% OPERATING	6	2031.0	245.8	11.6	14.4	17.18
120% OPERATING	6	1996.7	222.2	11.3	13.9	17.60
125% OPERATING	6	1976.1	209.2	11.1	13.7	17.81

SOURCE: NFLD. DEPT. OF MINES AND ENERGY

TABLE 8.

OFFSHORE NEWFOUNDLAND

EXCHANGE RATE ADJUSTMENT - PRICE AND COSTS

$ REAL CANADIAN 1990

	CRUDE OIL PRICE		COSTS			
			CAPITAL		OPERATING	
	EXCH. 0.75	EXCH. 0.90	EXCH. 0.75	EXCH. 0.90	EXCH. 0.75	EXCH. 0.90
PRICE (REVENUE)	26.67	22.22	-	-	-	-
COSTS	-	-	3878	3509	2053	1948
% DECREASE (.90/.75)		16.7%		9.5%		5.1%

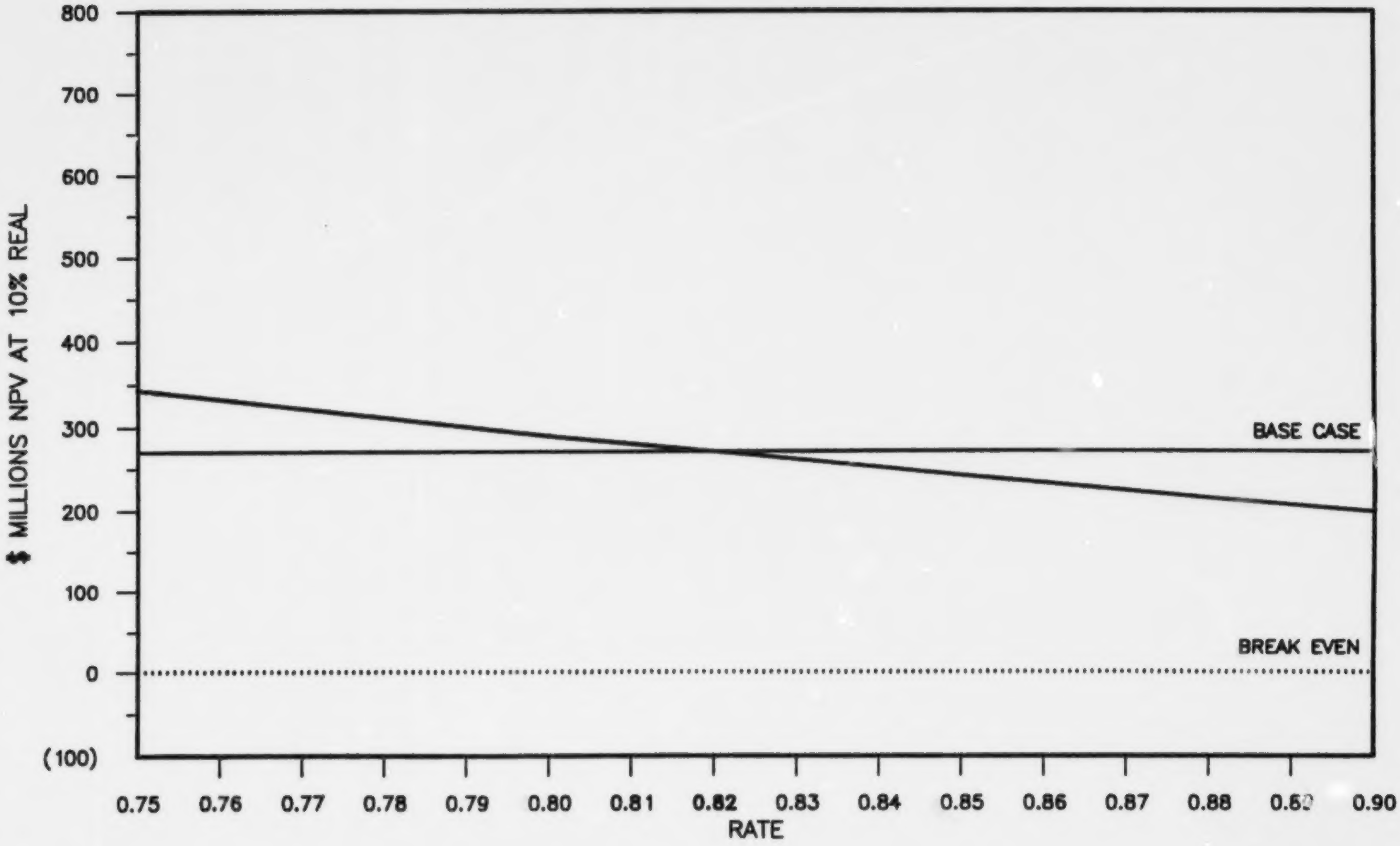
NOTES:

- PRICE CONVERTED FROM $20 U.S.
- CAPITAL COSTS CONVERTED FROM $3689 MILLION UNDER THE ASSUMPTION THAT 50% SUBJECT TO EXCHANGE RATE ADJUSTMENT
- OPERATING COSTS CONVERTED FROM $2000 MILLION UNDER THE ASSUMPTION THAT 25% SUBJECT TO EXCHANGE RATE ADJUSTMENT

SOURCE: NFLD. DEPT. OF MINES AND ENERGY

FIGURE 7

TERRA NOVA PROJECT
SENSITIVITY ANALYSIS RESULTS
EXCHANGE RATE



SOURCE: NFLD. DEPT. OF MINES AND ENERGY

TABLE 9.

TERRA NOVA PROJECT

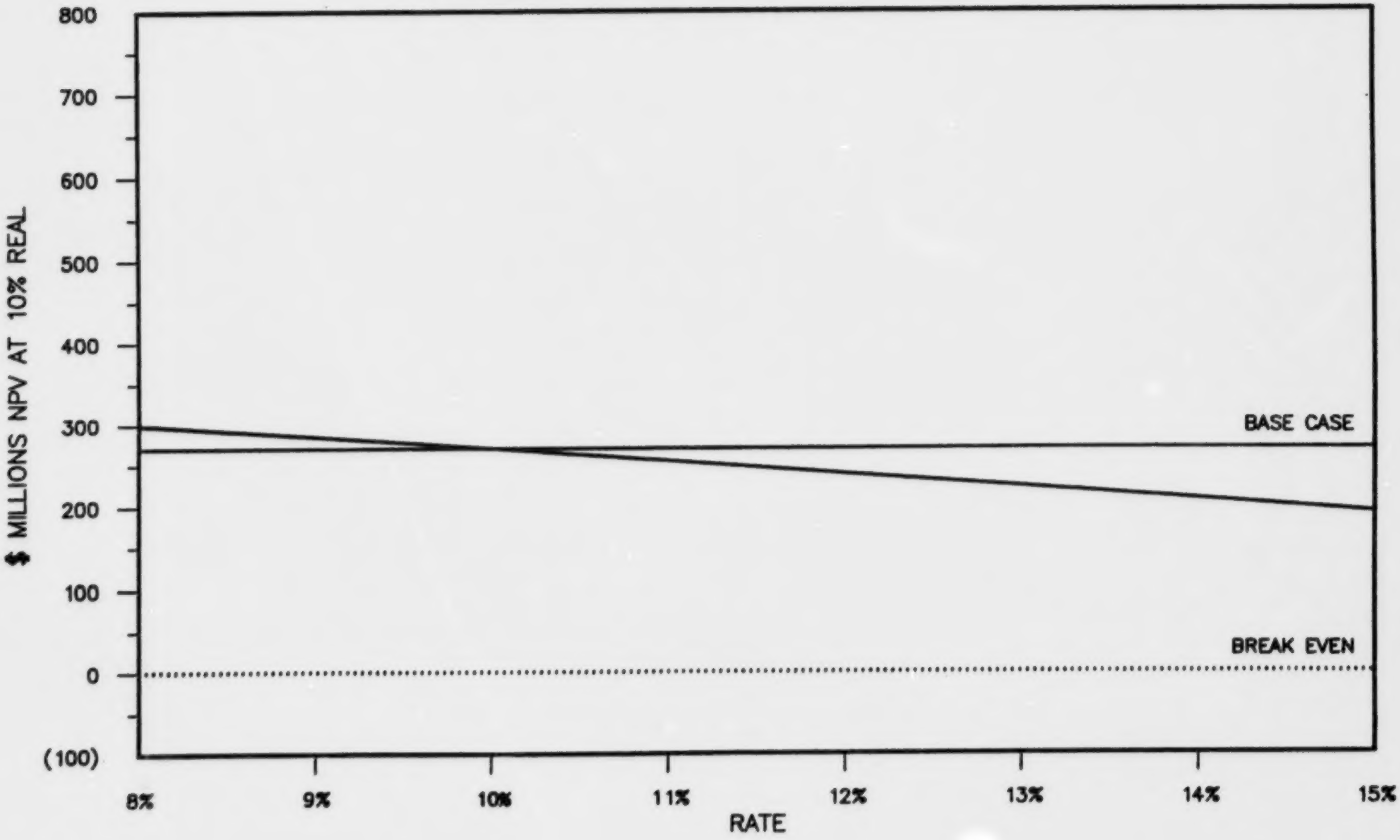
SENSITIVITY ANALYSIS RESULTS
EXCHANGE RATE

CASE	YEARS TO PAYBACK	$ MILLIONS CANADIAN		RATE OF RETURN (REAL TERMS)		SUPPLY PRICE ($ US, 1990/Bbl)
		NET CASH FLOW ($ REAL 1990)	NET PRESENT VALUE (AT 10% REAL)	TOTAL CAPITAL	EQUITY	
RATE 0.75	5	2298.5	344.1	12.6	15.9	17.44
RATE 0.78	6	2200.6	311.9	12.3	15.5	17.13
RATE 0.80	6	2131.5	289.6	12.1	15.1	16.94
RATE 0.82 (BASE CASE)	6	2079.4	270.8	11.9	14.8	16.76
RATE 0.85	6	1994.5	241.3	11.6	14.4	16.50
RATE 0.88	6	1923.9	214.7	11.3	13.9	16.26
RATE 0.90	6	1886.9	198.5	11.1	13.6	16.11

SOURCE: NFLD. DEPT. OF MINES AND ENERGY

FIGURE 8

TERRA NOVA PROJECT
SENSITIVITY ANALYSIS RESULTS
BORROWING RATE



SOURCE: NFLD. DEPT. OF MINES AND ENERGY

TABLE 10.

TERRA NOVA PROJECT

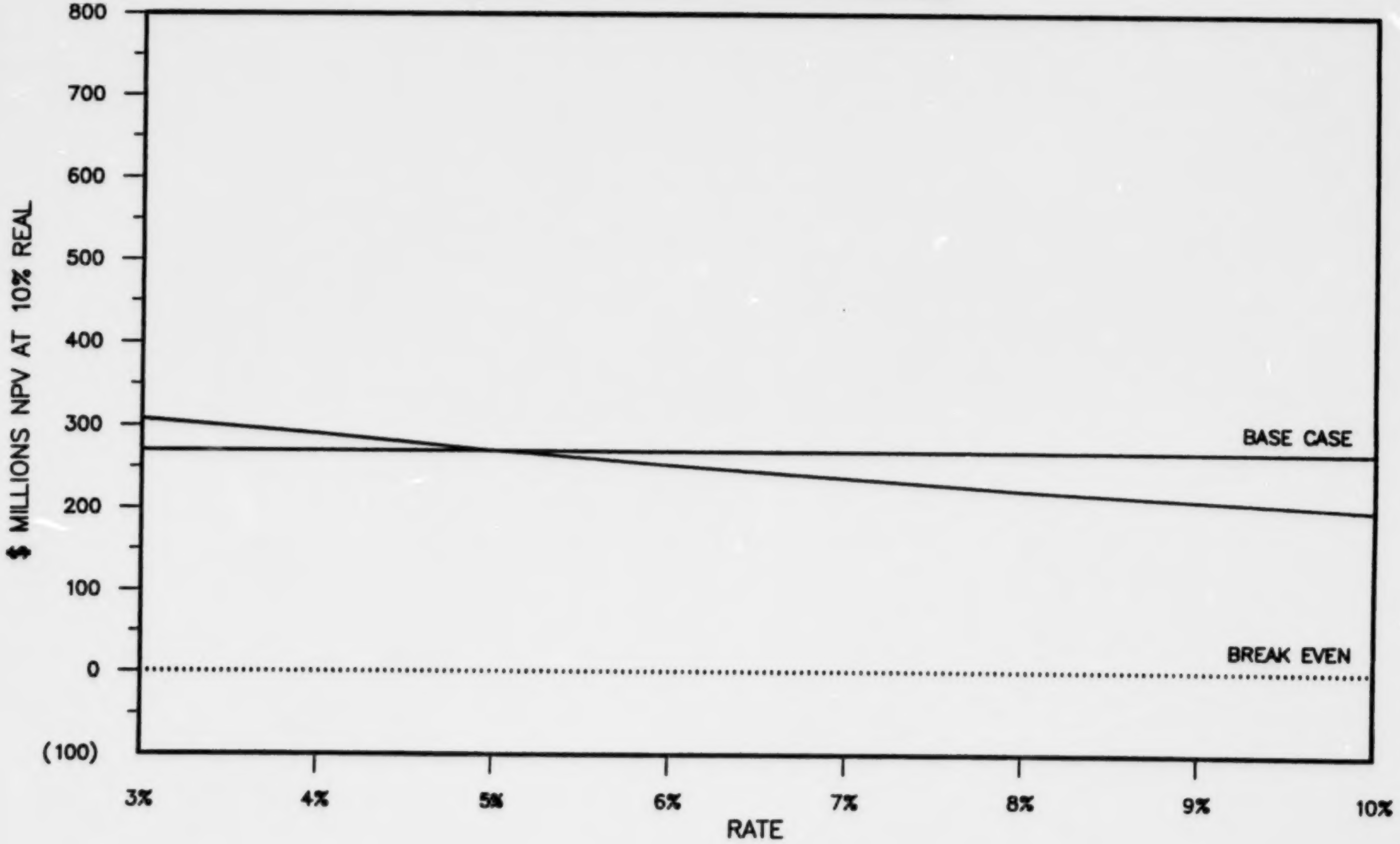
SENSITIVITY ANALYSIS RESULTS
BORROWING RATE

CASE	YEARS TO PAYBACK	$ MILLIONS CANADIAN		RATE OF RETURN (REAL TERMS)		SUPPLY PRICE ($ US. 1990/Bbl)
		NET CASH FLOW ($ REAL 1990)	NET PRESENT VALUE (AT 10% REAL)	TOTAL CAPITAL	EQUITY	
INTEREST 8%	6	2147.5	300.2	11.5	15.4	16.46
INTEREST 9%	6	2113.8	285.6	11.7	15.1	16.61
INTEREST 10% (BASE CASE)	6	2079.4	270.8	11.9	14.8	16.76
INTEREST 11%	6	2044.2	255.7	12.1	14.6	16.92
INTEREST 12%	6	2008.3	240.4	12.2	14.3	17.07
INTEREST 13%	6	1971.7	224.9	12.4	14.0	17.23
INTEREST 14%	6	1933.6	209.6	12.6	13.7	17.39
INTEREST 15%	6	1894.4	194.0	12.8	13.4	17.56

SOURCE: NFLD. DEPT. OF MINES AND ENERGY

FIGURE 9

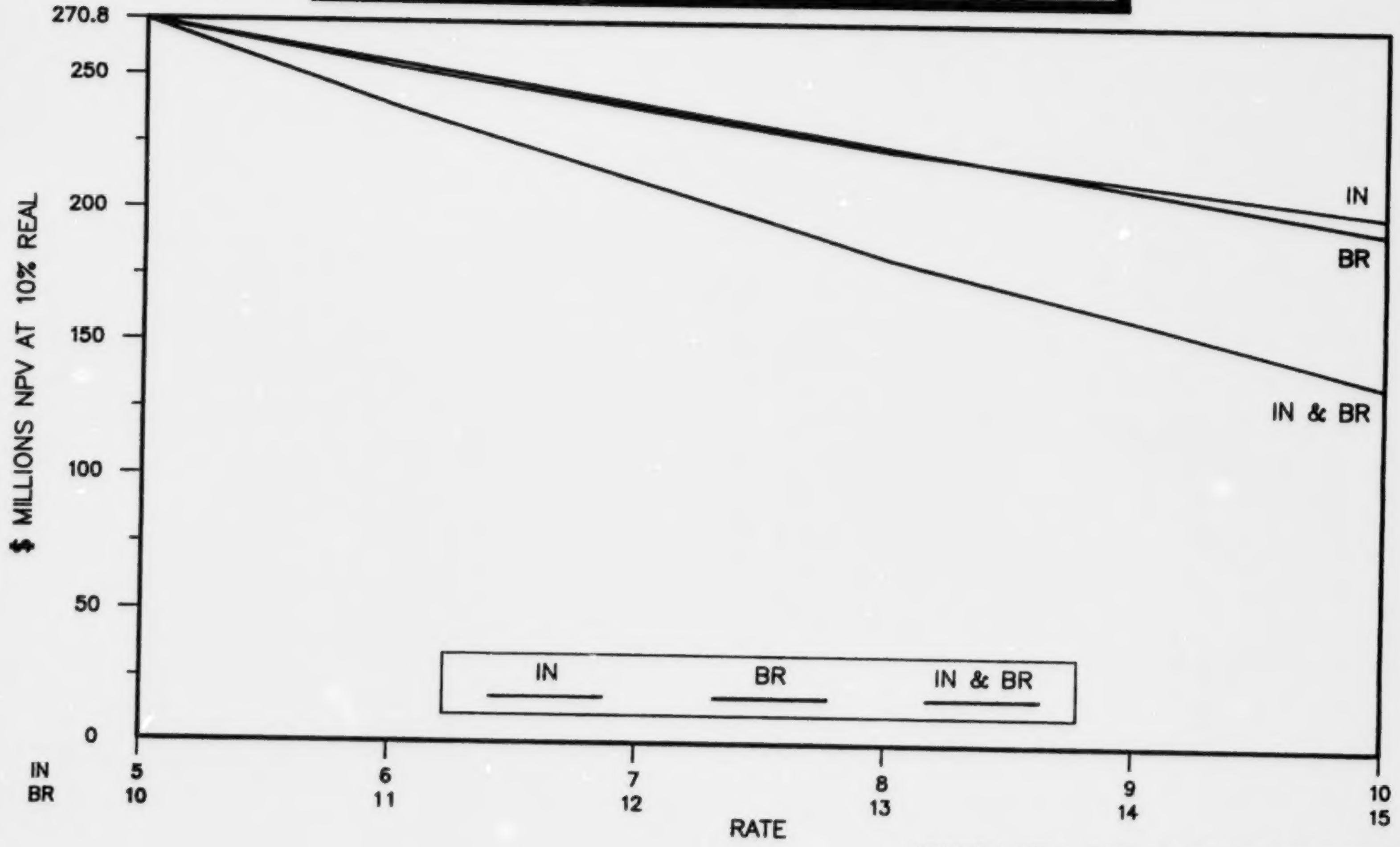
TERRA NOVA PROJECT
SENSITIVITY ANALYSIS RESULTS
INFLATION RATE



SOURCE: NFLD. DEPT. OF MINES AND ENERGY

FIGURE 10

TERRA NOVA PROJECT
SENSITIVITY ANALYSIS RESULTS
COMBINATION INFLATION RATE AND BORROWING RATE



SOURCE: NFLD. DEPT. OF MINES AND ENERGY

TABLE 11.

TERRA NOVA PROJECT

SENSITIVITY ANALYSIS RESULTS
INFLATION RATE

		$ MILLIONS CANADIAN		RATE OF RETURN (REAL TERMS)		
CASE	YEARS TO PAYBACK	NET CASH FLOW ($ REAL 1990)	NET PRESENT VALUE (AT 10% REAL)	TOTAL CAPITAL	EQUITY	SUPPLY PRICE ($ US. 1990/Bbl)
INFLATION 3%	6	2303.7	308.6	12.8	15.3	16.93
INFLATION 4%	6	2188.0	291.2	12.3	15.1	16.84
INFLATION 5% (BASE CASE)	6	2079.4	270.8	11.9	14.8	16.76
INFLATION 6%	6	2002.2	253.9	11.4	14.6	16.69
INFLATION 8%	7	1882.2	223.5	10.6	14.1	16.60
INFLATION 10%	7	1806.0	200.5	9.9	13.7	16.96

SOURCE: NFLD. DEPT. OF MINES AND ENERGY

TABLE 12.

OFFSHORE NEWFOUNDLAND

MINIMUM RESERVE SIZE SENSITIVITY

	MILLIONS OF BARRELS RECOVERABLE		
	(-)	BASE CASE	(+)
PRICE ($30, $20, $15)	102	153	204
CAPITAL COSTS (-25%, 0%, +25%)	127	153	180
OPERATING COSTS (-25%, 0%, +25%)	141	153	165
EXCHANGE RATES (0.75, 0.82, 0.90)	145	153	162
INTEREST RATES (8%, 10%, 15%)	150	153	160
INFLATION (3%, 5%, 10%)	153	153	153

SOURCE: NFLD. DEPT. OF MINES AND ENERGY

SPEAKER : **CLYDE C. GRANTER**

COMPANY : **DEPARTMENT OF DEVELOPMENT**
GOVERNMENT OF NEWFOUNDLAND AND LABRADOR

LOCATION: **ST. JOHN'S, NEWFOUNDLAND**

TOPIC : **THE IMPACT OF GOVERNMENTS' INDUSTRIAL BENEFITS POLICIES ON OFFSHORE PETROLEUM DEVELOPMENTS**

BIOGRAPHY: Clyde Granter is Deputy Minister, Department of Development, Government of Newfoundland and Labrador.

Mr. Granter attended Memorial University of Newfoundland and received his B.Sc. in 1965. He received his B.Eng. from the Technical University of Nova Scotia in 1967.

From 1967-72 Mr. Granter worked with Northern Electric Company Limited at various System Analysis positions. He worked with Domtar Limited as Senior Systems Analysts; Manager Systems Development from 1972-77. In 1977 he joined the Government of Newfoundland and Labrador, where he has held such positions as Director, Organization and Management, Treasury Board (1977-80); Assistant Deputy Minister, Industrial Services, Department of Development (1980-85); and his present position since 1985.

Mr. Granter is a Director of the Marystown Shipyard Limited and a member of the Board of Governors for the centre for Cold Ocean Resources Engineering (C-CORE), Memorial University.

ABSTRACT

THE IMPACT OF GOVERNMENTS' INDUSTRIAL BENEFITS POLICIES ON OFFSHORE PETROLEUM DEVELOPMENTS

Governments have, for some time, viewed large-scale petroleum-related projects as the impetus to development of industrial infrastructure. While the other fiscal policy issues concerning royalties and taxation are important to our economy, long-term industrial growth and the creation of necessary support industries bring into balance the overall objectives of governments.

In determining strategic benefits objectives the Province aims to ensure its position fosters the development of long-term industrial and employment base, with the requisite skills that allow for ever increasing local capabilities. The intent, of course, is to facilitate the involvement by Newfoundland firms and residents in any offshore development projects.

The rationale for the Provinces' industrial benefits policies is based on a desire to ensure that Newfoundland does, in fact, become the principle beneficiary from the exploitation of oil and gas resources in the Newfoundland offshore area, particularly in accordance with the benefits requirements of the Atlantic Accord Implementation Acts.

To accomplish our objectives, the Province attempts to achieve specific commitments from operators for particular work packages to be executed in Newfoundland, rather than to merely rely on general benefits policies of operators. As well, the Province has implemented several programs and other initiatives utilizing the Offshore Development Fund to enhance local capabilities and to prepare Newfoundland residents for the numerous opportunities afforded by major offshore developments.

NEWFOUNDLAND'S ECONOMIC STRUCTURE FACES DIFFICULTIES RESULTING FROM THE INHERENT CHARACTERISTICS OF A RESOURCE BASED ECONOMY. THE PROVINCE'S WEAK GOODS-PRODUCING SECTOR SUBJECTS THE ECONOMY TO AN ABNORMALLY HIGH LEAKAGE EFFECT AS MOST CONSUMER AND INDUSTRIALIZED GOODS ARE PRODUCED OUTSIDE THE PROVINCE. THIS LEAKAGE EFFECT COMPOUNDS THE PROBLEM NEWFOUNDLAND FACES IN GENERATING SELF-SUSTAINING ECONOMIC GROWTH. SUCH PROBLEMS ARE EVIDENCED BY THE FACT THAT GOVERNMENT IS, BY FAR, THE SINGLE LARGEST EMPLOYER AND THE SERVICE SECTOR EXCEEDS THE GOODS-PRODUCING SECTOR BOTH IN TERMS OF THE VALUE OF OUTPUT AND EMPLOYMENT GENERATED.

NEWFOUNDLAND LAGS BEHIND THE REST OF CANADA IN ALMOST EVERY MEASURE OF ECONOMIC ACTIVITY. THE MOST DRAMATIC EXPRESSION OF THIS TRANSLATED ECONOMIC DISPARITY IS SEEN IN THE LEVEL OF UNEMPLOYMENT. IN 1989, THE CANADIAN UNEMPLOYMENT RATE AVERAGED 7.5 PERCENT WHILE IN NEWFOUNDLAND THE UNEMPLOYMENT RATE AVERAGED 15.8 PERCENT, MORE THAN TWICE THE NATIONAL AVERAGE. NEWFOUNDLAND'S ECONOMIC DISPARITY IS FURTHER EMPHASIZED IN TERMS OF GROSS INVESTMENT WHERE NEWFOUNDLAND FALLS BEHIND THE NATIONAL AVERAGE BY 33.3% ON A PER CAPITA BASIS.

IT IS IMPERATIVE THAT A PROVINCE WITH THIS TYPE OF DISPARITY MAKE ECONOMIC DEVELOPMENT AND GROWTH A CENTRAL FOCUS OF GOVERNMENT POLICY. SINCE INVESTMENT IS THE FUEL OF ANY ECONOMY, A NARROWING OF THE NEWFOUNDLAND/CANADA INVESTMENT GAP MUST BE THE MEDIUM THROUGH WHICH OTHER ECONOMIC DISPARITIES ARE ADDRESSED. GOVERNMENT MUST, THEREFORE, IDENTIFY INVESTMENT OPPORTUNITIES IN THE PROVINCE AND ADOPT POLICY TO REALIZE THESE OPPORTUNITIES.

A PRIMARY OPPORTUNITY FOR THE PROVINCE OF NEWFOUNDLAND IS THE DEVELOPMENT OF ITS OFFSHORE PETROLEUM RESOURCES. IT IS RECOGNIZED THAT MAJOR PROJECTS ASSOCIATED WITH THE OIL INDUSTRY CAN CONTRIBUTE SUBSTANTIALLY TO THE DEVELOPMENT OF VIABLE LONG TERM INDUSTRIAL CAPABILITY AS WELL AS FOSTER INDUSTRIAL GROWTH, DIVERSIFICATION, AND INVESTMENT. WHILE FISCAL POLICY ISSUES CONTRIBUTE TO IMPROVEMENTS IN THE OVERALL DEVELOPMENT OF AN ECONOMY, BOTH LONG TERM INDUSTRIAL GROWTH AND THE CREATION OF NECESSARY SUPPORT INDUSTRIES BRING INTO BALANCE PRODUCTIVE LABOUR AND CAPITAL. FOR THIS REASON GOVERNMENT HAS DEVELOPED AN INDUSTRIAL BENEFITS POLICY TO OPTIMIZE INDUSTRIAL AND EMPLOYMENT OPPORTUNITIES.

THE POLICY RESPECTING INDUSTRIAL BENEFITS IS PUT FORWARD IN THE ATLANTIC ACCORD, A MEMORANDUM OF AGREEMENT BETWEEN THE GOVERNMENT OF CANADA AND THE GOVERNMENT OF NEWFOUNDLAND AND LABRADOR ON OFFSHORE OIL AND GAS RESOURCE MANAGEMENT AND INCOME SHARING. IT ENSURES THAT THE OFFSHORE AREA IS MANAGED IN A MANNER WHICH WILL PROMOTE ECONOMIC GROWTH AND DEVELOPMENT IN ORDER TO ASSURE BENEFITS ACCRUE TO NEWFOUNDLAND, IN PARTICULAR, AND CANADA AS A WHOLE. IT FURTHER REQUIRES THE DEVELOPER TO RESPOND TO INDUSTRIAL BENEFITS WITH A PLAN FOR THE EMPLOYMENT OF THE CANADIAN AND, IN PARTICULAR, THE PROVINCIAL LABOUR FORCE. THE ACCORD ALSO ENSURES THAT NEWFOUNDLAND FIRMS ARE GIVEN FULL AND FAIR OPPORTUNITY TO PARTICIPATE IN THE SUPPLY OF GOODS AND SERVICES WHERE SUCH GOODS AND SERVICES ARE COMPETITIVE IN TERMS OF FAIR MARKET PRICE, QUALITY AND DELIVERY. THE AGREEMENT ALSO PROVIDES FOR FIRST CONSIDERATION IN TRAINING AND EMPLOYMENT OPPORTUNITIES FOR INDIVIDUALS RESIDENT IN NEWFOUNDLAND, ALLOWING FOR THE SUCCESSION OF FOREIGN PERSONNEL BY RESIDENTS OF NEWFOUNDLAND AND CANADA.

GOVERNMENT BELIEVES THE DEVELOPMENT OF THIS POLICY IS A RATIONAL APPROACH TO MEETING THE OBJECTIVES OF ECONOMIC DEVELOPMENT AND GROWTH. WITH RESPECT TO NON-RENEWABLE RESOURCES, THE POLICY WILL ALLOW AN OFFSHORE OPERATOR TO COMPLETE AN OFFSHORE OIL PROJECT IN AN EFFICIENT AND COST-EFFECTIVE MANNER. IN GENERAL, THE BENEFITS POLICY IMPLIES A RECOGNITION OF DEPENDENCE UPON OUTSIDE INTERESTS AND A WILLINGNESS TO ALLOW SUCH INTERESTS TO MAKE A SIGNIFICANT

CONTRIBUTION TO OFFSHORE OIL DEVELOPMENT. THE PROVINCE AND THE REST OF CANADA WILL BE ENSURED OF THE DEVELOPMENT OF AN INDUSTRIAL BASE WITH THE REQUISITE TRADES, PROFESSIONAL SKILLS, AND INFRASTRUCTURE NECESSARY TO INCREASE PARTICIPATION IN OTHER HIGH TECH INDUSTRIES.

THE INDUSTRIAL BENEFITS POLICY FOR THE HIBERNIA PROJECT HAS RESULTED IN MOBIL AND ITS PARTNERS PROPOSING A STRATEGY TO ACHIEVE CANADA/NEWFOUNDLAND BENEFITS. THIS BENEFITS STRATEGY CAN BE SUMMARIZED AS FOLLOWS:

- ESTABLISH A MANAGEMENT ORGANIZATION TO ENSURE DIRECT CONTROL OVER ALL ASPECTS OF PROJECT EXECUTION INCLUDING DESIGN, CONSTRUCTION, AND OPERATION OF FACILITIES;

- ENSURE THE MANAGEMENT ORGANIZATION IS WELL INFORMED OF NATIONAL AND LOCAL SUPPLY CAPABILITIES;

- AT APPROPRIATE STAGES DURING THE PROJECT, IDENTIFY NATIONAL AND LOCAL SUPPLY CAPABILITIES THROUGH METHODS SUCH AS VENDOR SURVEYS, AND AS SOON AS FEASIBLE AFTER PROJECT APPROVAL, BEGIN COMMUNICATING PROJECT REQUIREMENTS TO THE CANADA/NEWFOUNDLAND BOARD, LOCAL AND NATIONAL BUSINESS ASSOCIATIONS, BUSINESSES, INDUSTRY AND GOVERNMENTS;

- DEVELOP DETAILED EQUIPMENT LISTS AS PART OF INFORMATION PACKAGES AT THE EARLIEST APPROPRIATE TIMES DURING THE PROJECT SCHEDULE FOR DISTRIBUTION AS WIDELY AS PRACTICAL TO THE CANADA-NEWFOUNDLAND BOARD, BUSINESS ASSOCIATIONS, BUSINESSES AND INDUSTRY IN GENERAL. INFORMATION WILL INCLUDE DETAILS ON EQUIPMENT AND MATERIALS REQUIRED TO BE PURCHASED:
  - DIRECTLY BY MOBIL
  - BY MAIN CONTRACTORS
  - BY SUBCONTRACTORS;

- CONTINUE TO SUPPORT LOCAL RESEARCH INSTITUTIONS AND PROMOTE FURTHER RESEARCH AND DEVELOPMENT IN CANADA TO SOLVE PROBLEMS UNIQUE TO THE CANADIAN OFFSHORE ENVIRONMENT;

- AS SOON AS PERSONNEL AND SKILL NEEDS REQUIREMENTS ARE IDENTIFIED, COMMUNICATE THESE REQUIREMENTS TO THE CANADA-NEWFOUNDLAND BOARD, EDUCATIONAL INSTITUTIONS AND THE PUBLIC, AND CONTINUE TO UPDATE ON A REGULAR BASIS;

- PROMOTE A CLEAR UNDERSTANDING OF THE SCALE AND TIMING OF THE PROJECT THROUGH DIRECT COMMUNICATION AND CONSULTATION WITH NEWFOUNDLAND COMMUNITIES, INSTITUTIONS, AND RESIDENTS. DEVELOP SPECIFIC PROJECT INFORMATION PROGRAMS FOR COMMUNITIES AFFECTED BY PROJECT-RELATED ACTIVITIES. SUCH PROGRAMS WILL BE COMMUNICATED TO INTERESTED GROUPS SUCH AS COMMUNITY ADVISORY

COMMITTEES, TOWN COUNCILS; AND APPROPRIATE GOVERNMENT AGENCIES;

- PARTICIPATE IN COMMUNITY ADVISORY COMMITTEES TO DISCUSS SOLUTIONS TO PROBLEMS RELATED TO SITE-SPECIFIC INDUSTRY-COMMUNITY IMPACTS.

OVERALL INDUSTRIAL BENEFITS POLICY HAS RESULTED IN A GROUP OF WORK ITEMS OF STRATEGIC IMPORTANCE IN OPTIMIZING NEWFOUNDLAND AND CANADIAN CONTENT. THE STATEMENT OF PRINCIPLES SIGNED IN JULY 1988 IS A COMMITMENT TO A DEFINED PERCENTAGE CONTENT FOR THE TOTAL PROJECT BROKEN OUT INTO FOUR PROJECT ELEMENTS: PROJECT MANAGEMENT, ENGINEERING, FABRICATION, AND CONSTRUCTION.

THE GOVERNMENT OF NEWFOUNDLAND REVIEWED EXISTING STUDIES AND OTHER APPROPRIATE DATA TO FORMULATE A STRATEGY TO GUARANTEE NEWFOUNDLAND'S PARTICIPATION IN THE DESIGN AND CONSTRUCTION ACTIVITIES OF THE HIBERNIA GRAVITY BASED PRODUCTION SYSTEM. ENSURING NEWFOUNDLAND PARTICIPATION REQUIRED A GOAL ORIENTED STRATEGY; ON ONE LEVEL ACKNOWLEDGING WHAT WORK WHICH COULD BE PERFORMED IN NEWFOUNDLAND BASED ON THE PROVINCE'S CURRENT CAPABILITY AND, MORE IMPORTANTLY, WORK WHICH COULD BE ATTAINABLE WITH THE PROVISION OF NECESSARY TRAINING, INFRASTRUCTURE, AND CAPITAL.

THIS GOAL ORIENTED STRATEGY REQUIRES THAT THE PROVINCE TAKE ALL PRACTICAL ACTION TO ENSURE:

- THE AVAILABILITY OF BOTH SKILLED AND TRAINABLE PERSONNEL;
- THE AVAILABLITY OF WORK SITES TO SATISFY THE LEVEL OF WORK SOUGHT;
- THAT THE PROJECT WOULD NOT BE UNDULY HANDICAPPED IN TIME, COST, OR QUALITY .

EFFORTS BY THE PROVINCIAL GOVERNMENT TO MEET THE OBJECTIVES OF THE BENEFITS STRATEGY INCLUDE ORGANIZATION OF TRADE MISSIONS AND TRADE SHOWS AND PROMOTION OF JOINT VENTURES. SINCE 1985, THE PROVINCIAL GOVERNMENT HAS BEEN ORGANIZING AND LEADING BUSINESS DEVELOPMENT MISSIONS TO THE NORTH SEA WHICH RELATE DIRECTLY TO OFFSHORE OIL AND GAS DEVELOPMENT. SUCH MISSIONS HAVE BEEN INSTRUMENTAL IN ESTABLISHING JOINT VENTURES, EXPOSING NEWFOUNDLAND FIRMS TO OTHER DEVELOPMENT PROJECTS AND TECHNOLOGY, AND INTRODUCING NEWFOUNDLAND EXPERTISE AND TECHNOLOGY TO FOREIGN OPERATORS. NEWFOUNDLAND FIRMS, IN CONJUNCTION WITH THE DEPARTMENT OF DEVELOPMENT, HAVE ALSO BEEN ATTENDING TRADE SHOWS ON A REGULAR BASIS SINCE 1975. PRESENCE AT INTERNATIONAL SHOWS HAS INCREASED AWARENESS OF AND INTEREST IN NEWFOUNDLAND'S OFFSHORE OIL AND GAS DEVELOPMENTS. IN ADDITION TO ATTENDING TRADE SHOWS, THE PROVINCE ALSO PLAYS HOST AT OFFSHORE

NEWFOUNDLAND WHICH IS ORGANIZED ANNUALLY BY A LOCAL COMPANY WITH SUPPORT AND ASSISTANCE FROM THE DEPARTMENT OF DEVELOPMENT. IN ADDITION, A NUMBER OF JOINT VENTURES HAVE BEEN ESTABLISHED WITH FOREIGN FIRMS WHICH PROVIDE OPPPORTUNITIES FOR TECHNOLOGY TRANSFER AND THE SHARING OF FUNDS AND EXPERTISE.

IT IS ONLY THROUGH THE STATED INDUSTRIAL BENEFITS POLICY THAT THE PROVINCE WILL BE IN A POSITION TO OBTAIN SIGNIFICANT OPPORTUNITIES IN THE OFFSHORE OIL INDUSTRY AND TO PARTICIPATE IN OTHER TECHNOLOGY-RELATED PROJECTS. THE PROVINCE OF NEWFOUNDLAND HAS LEARNED THIS LESSON FROM THE EXPERIENCE OF PARTICIPATING COUNTRIES IN THE NORTH SEA OIL AND GAS DEVELOPMENTS, MOST NOTABLY THE UNITED KINGDOM AND NORWAY. BOTH NATIONS HAVE PROGRESSIVELY INCREASED THEIR SHARE OF SUPPLY REQUIREMENTS TO THE OFFSHORE INDUSTRY. IN 1975 THE NORWEGIAN SHARE OF TOTAL OFFSHORE ORDERS WAS 28 PERCENT AND HAS INCREASED TO BETWEEN 50 AND 60 PERCENT IN 1989, A FIGURE WHICH HAS REMAINED CONSTANT FOR SEVERAL YEARS. THE ULTIMATE GOAL OF NORWAY IS TO PROVIDE 75 PERCENT OF ALL REQUIREMENTS FOR GOODS AND SERVICES IN THE OFFSHORE SECTOR. COMPARATIVELY, IN 1975 THE UNITED KINGDOM ACHIEVED 52 PERCENT OF ALL REQUIREMENTS FOR GOODS AND SERVICES IN THE OFFSHORE SECTOR AND HAS INCREASED THIS FIGURE TO APPROXIMATELY 80 PERCENT IN 1989.

THE HISTORICAL DEVELOPMENT OF THE OIL INDUSTRY IN THE UNITED KINGDOM AND NORWAY OFFERS CANADA AND THE PROVINCE OF NEWFOUNDLAND THE OPPORTUNITY TO LEARN VALUABLE LESSONS IN THE DEVELOPMENT AND IMPLEMENTATION OF INDUSTRIAL BENEFITS POLICY. HOWEVER, IT MUST BE NOTED THAT THE NATURE OF CANADA, AND OF NEWFOUNDLAND IN PARTICULAR, DIFFERS IN TERMS OF CULTURE, ECONOMICS, GEOGRAPHY, HISTORY, AND POLITICAL DEVELOPMENT. FOR THIS REASON THE IMPLEMENTATION OF OFFSHORE POLICY MUST RESPOND TO THE NEEDS OF BOTH CANADA AND NEWFOUNDLAND. FOR EXAMPLE, IMPORTANT TO THE DEVELOPMENT OF OFFSHORE BENEFITS POLICY WAS INTERACTION WITH THE BUSINESS AND LABOUR COMMUNITY TO GAUGE THEIR ABILITIES AND NEEDS WITH RESPECT TO THE OIL INDUSTRY. THROUGH GROUPS SUCH AS THE NEWFOUNDLAND OCEAN INDUSTRIES ASSOCIATION, VARIOUS CHAMBERS OF COMMERCE, BOARD OF TRADE, AND LABOUR ASSOCIATIONS AND FEDERATIONS, THE GOVERNMENT OF NEWFOUNDLAND WAS ABLE TO IDENTIFY THAT DEVELOPMENT OF THE OFFSHORE SHOULD OPTIMIZE THE BENEFITS ACCRUED TO NEWFOUNDLAND. ALTHOUGH THE CREATION OF JOBS AND BUSINESS OPPORTUNITIES IS IMPORTANT, BUSINESS AND LABOUR ALSO REQUIRE THE DEVELOPMENT OF A SKILLED LABOUR FORCE AND BUSINESS OPPORTUNITIES IN THE MANUFACTURING SECTOR. HOWEVER, THE OBJECTIVES OF BUSINESS, LABOUR, AND GOVERNMENT ARE TO BE ACHIEVED THROUGH "OPEN MARKET" MECHANISMS REQUIRING NEWFOUNDLAND FIRMS TO BE COMPETITIVE.

THE SIGNING OF THE ATLANTIC ACCORD WAS AN INITIAL STEP IN A COOPERATIVE APPROACH TO MEETING THE CHALLENGE OF CREATING LONG TERM BENEFITS. THE ACCORD ESTABLISHED THE CANADA NEWFOUNDLAND OFFSHORE PETROLEUM BOARD TO ADMINISTER FEDERAL AND PROVINCIAL LEGISLATION RESPECTING OFFSHORE PETROLEUM RESOURCES AND, THUS, SETTLING A LONG STANDING DISAGREEMENT ON THE MANAGEMENT OF OFFSHORE RESOURCES. MORE IMPORTANTLY, HOWEVER, THE ACCORD ENSURED THAT THE OFFSHORE AREA "IS MANAGED IN A MANNER WHICH PROMOTES ECONOMIC GROWTH AND DEVELOPMENT OPTIMIZING BENEFITS TO NEWFOUNDLAND IN PARTICULAR, AND TO CANADA AS A WHOLE". AT THE SAME TIME THE ACCORD ENSURES FULL AND FAIR OPPORTUNITY TO NEWFOUNDLAND COMPANIES IN THE PROVISION OF GOODS AND SERVICES.

THE IMPORTANCE OF THESE STATEMENTS IS EVIDENCED FROM THE EXPERIENCE OF THE UNITED KINGDOM. ITS SPEED TO EXPLOIT OFFSHORE RESOURCES RESULTED IN A FAILURE TO ACKNOWLEDGE THE IMPORTANCE OF FULL AND FAIR OPPORTUNITY AND FIRST CONSIDERATION CLAUSES, THEREBY REDUCING THE OPPORTUNITIES OF BRITISH COMPANIES TO PARTICIPATE AS SUPPLIERS. THE UNITED KINGDOM WAS FACED WITH THE REALIZATION THAT THE LACK OF A LOCAL SOURCING POLICY PLACED A NEWLY CREATED SUPPLIES INDUSTRY AT A DISADVANTAGE RELATIVE TO WELL ESTABLISHED FOREIGN COMPETITORS.

THE SIGNATORIES TO THE ATLANTIC ACCORD ALSO RECOGNIZED THE NEED TO PROVIDE A FINANCIAL SUPPORT MECHANISM TO DEFRAY THE COSTS OF SOCIAL AND ECONOMIC INFRASTRUCTURE RELATED TO DEVELOPMENT OF AN OIL ECONOMY AND TO ENSURE THAT THE PROVINCIAL ECONOMY IS WELL POSITIONED TO REAP THE ECONOMIC BENEFITS OF OIL DEVELOPMENT. THE ACCORD PROVIDED FOR THE ESTABLISHMENT OF A FIVE YEAR 300 MILLION DOLLAR OFFSHORE DEVELOPMENT FUND. THIS FUND WAS IN ADDITION TO FINANCIAL SUPPORT PROVIDED THROUGH THE CANADA/NEWFOUNDLAND OCEAN INDUSTRY DEVELOPMENT SUBSIDIARY AGREEMENT, A PROGRAM FOCUSING ON OCEAN INDUSTRY DEVELOPMENT, THE ATLANTIC CANADA OPPORTUNITIES AGENCY AND THE NEWFOUNDLAND & LABRADOR DEVELOPMENT CORPORATION. MONIES SPENT THROUGH THESE FUNDING MECHANISMS FOCUS ON EDUCATION AND TRAINING, MARKETING, CAPITAL ASSISTANCE, AND RESEARCH AND DEVELOPMENT INITIATIVES TO THE BENEFIT OF THE NEWFOUNDLAND OFFSHORE OIL INDUSTRY.

THE IMPLEMENTATION OF THE INDUSTRIAL BENEFITS POLICY IS A CONCERTED EFFORT TO FOSTER THE DEVELOPMENT OF A LONG TERM INDUSTRIAL AND EMPLOYMENT BASE. IT WILL ALSO PROVIDE THE REQUISITE SKILLS THAT ALLOW FOR EVER INCREASING LOCAL CAPABILITIES TO PURSUE INCREASED PARTICIPATION IN OFFSHORE OIL DEVELOPMENT AND OTHER NON-OIL INDUSTRIAL OPPORTUNITIES. ALL OIL PRODUCING ECONOMIES MAINTAIN INDUSTRIAL BENEFITS POLICIES, HOWEVER THE POLICY PUT FORWARD IN THE ATLANTIC ACCORD DOES NOT RESTRICT OPPORTUNITIES FOR SUPPLY FIRMS WILLING TO PARTICIPATE IN THE NEWFOUNDLAND OIL ECONOMY.

IMPLEMENTATION OF GOVERNMENT'S INDUSTRIAL BENEFITS POLICY IS IN THE EARLY STAGES, THEREFORE ITS IMPACT IS DIFFICULT TO ASSESS. BASED ON ACTIVITY TO DATE, PARTICIPATING OIL COMPANIES SEEM TO HAVE COOPERATED WITH THE POLICY, NEGOTIATING IN GOOD FAITH WITH RESPECT TO BENEFITS OBJECTIVES. IN MANY INSTANCES THE OIL COMPANIES HAVE ASSISTED IN PROMOTING THE USE OF JOINT VENTURES AND THE DEVELOPMENT OF LOCAL SUPPLY CAPABILITIES.

WITH RESPECT TO LOCAL INDUSTRY, INCREASING NUMBERS OF LOCAL BUSINESSES ARE ENTERING THE INTERNATIONAL MARKETPLACE AND BIDDING FOR CONTRACTS PRIOR TO THE DEVELOPMENT OF HIBERNIA. SUCH ACTIVITY IS DUE PRIMARILY TO THE INCREASING LEVEL OF SKILL AND PRODUCTIVITY OF OUR WORKFORCE AND THE PARTICIPATION OF LOCAL BUSINESS IN COOPERATIVE AND JOINT VENTURE ARRANGEMENTS.

WHILE THE PROVINCE HAS ACTIVELY PURSUED OPPORTUNITIES FOR THE NEWFOUNDLAND BUSINESS AND LABOUR COMMUNITY, AN OVERALL BENEFITS STRATEGY HAS BEEN IMPLEMENTED WHICH RELIES HEAVILY ON THE EXPERIENCE OF OIL DEVELOPMENTS ON AN INTERNATIONAL SCALE. THE PROVINCE WELCOMES VISITORS FROM THE INTERNATIONAL COMMUNITY AS WELL AS OUR FELLOW CANADIANS TO PARTICIPATE IN THE DEVELOPMET OF HIBERNIA AND OTHER FUTURE OIL DEVELOPMENTS.

SPEAKER : **CHARLES LESTER**

COMPANY : **DEPARTMENT OF MINES AND ENERGY**
GOVERNMENT OF NEWFOUNDLAND AND LABRADOR

LOCATION: **ST. JOHN'S, NEWFOUNDLAND**

TOPIC : **HIBERNIA - ENVIRONMENTAL/SOCIO-ECONOMIC IMPACT ASSESSMENT PROCESS**

BIOGRAPHY: Mr. Lester graduated from Memorial University of Newfoundland in 1969 with a Bachelor of Commerce Degree and went directly into the Newfoundland Public Service as a Treasury Board Analyst. In 1974, he moved to the Cabinet Secretariat as a Social Policy Analyst until 1980 and as a Resource Policy Analyst until 1985. Mr. Lester joined the former Petroleum Directorate, now the Department of Mines and Energy, in 1985 and currently holds the position of Director of Policy, Planning and Coordination. He has also served on an extended secondment basis, in 1988 and 1989, as Assistant Secretary to Cabinet for Social Policy and Executive Secretary to the Provincial Government Task Force on Mathematics and Science.

ABSTRACT

This paper will review the environmental/socio-economic impact assessment process which is itself a relatively new and evolving process, but becoming increasingly important as attention focuses on such issues as global warming and sustainable development. The paper will begin with the early mentions of environmental protection in the 1977 Government of Newfoundland White Paper Respecting The Administration And Distribution Of Petroleum, reference the Environmental Assessment Act (NFLD) of 1980, and follow through the joint federal/provincial process adopted as the result of the Atlantic Accord. Special attention will be given to the use of an environmental protection plan (EPP) process for Hibernia related construction activity on land. In addition the paper will outline the mechanisms put in place through Memoranda of Understanding to resolve questions of possible jurisdictional overlap. The paper will also show how concerns for public information, consultation and participation are addressed throughout the evolving process. The paper will conclude with a status report on "where we are now" and outline mechanisms in place to monitor the project from an environmental/socio-economic perspective.

HIBERNIA

Environmental/Socio-Economic Impact Assessment Process

Introduction

Environmental Assessment is a relatively new and evolving process. Early initiatives focused on protection of the bio-physical environment in the immediate vicinity of development projects. Today environmental concerns are much broader in scope than bio-physical impacts and now include social and economic impacts well beyond immediate construction sites.

Today, I will review the Hibernia project from an environmental/socio-economic impact management perspective. To back up just a little, environmental legislation is not all that new in Newfoundland. As early as 1970, Newfoundland had enacted legislation to protect the environment, namely the Clean Air, Water and Soil Authority Act. In 1977, Government issued A White Paper which outlined the policy objectives of Government with respect to petroleum development. The White Paper gave prominent attention to the socio-economic impacts of petroleum developments and emphasized the need for a full analysis, including public hearings, of the environmental consequences of offshore petroleum development. The White Paper also referenced the need for a coordinated approach, with the Government of Canada, to the shared responsibility for certain environmental protection issues.

In 1980, Government proclaimed the Newfoundland and Labrador Environmental Assessment Act. This Act provides a mechanism whereby the environmental concerns of a proposed development are reviewed by a technical assessment committee and recommendations on the environmental acceptability of proposed undertakings are made to the Minister of the Environment who makes the final decision as to whether or not a project may proceed, and if so, under what conditions. This legislation was quite progressive at the time and subsequently served as model for the development of environmental assessment legislation in other jurisdictions in Canada.

Petroleum Directorate

In 1979, following the Hibernia discovery, the Government of Newfoundland and Labrador established the Petroleum Directorate to administer the Petroleum and Natural Gas Act (and Regulations), and to be the lead agency of Government in achieving the policy objectives set out in the Province's 1977 White Paper on Petroleum Policy. The Petroleum Directorate was provided with a twofold sociological objective - to plan for and ensure appropriate social research aimed at facilitating management by Government of any social impacts of oil and gas activity, and to plan for and ensure that the affected public would be effectively involved in this impact management effort. To accommodate these objectives, specialists in social research and community relations were hired in early 1980 and, initially, emphasis was placed on community relations and public participation efforts. A public participation model based on the principle of co-operation and co-ordination with other Government departments and relevant outside agencies was adopted.

OPIC

In 1980, the Newfoundland Government established, at the Deputy Minister level, the Offshore Petroleum Impact Committee (OPIC), with several sectoral sub-committees to co-ordinate the limited resources of the various departments and to ensure that the necessary planning studies were undertaken on a timely basis. A number of Advisory Councils, representing the general public and a variety of public interest groups, were also established to advise the Offshore Petroleum Impact Committee. Since that time, government departments and agencies have developed considerable knowledge and expertise in dealing with petroleum related matters.

The Atlantic Accord

In February, 1985, The Atlantic Accord, a memorandum of agreement on offshore oil and gas resource management and revenue sharing, was signed by the Government of Canada and the Government of Newfoundland and Labrador. This agreement provided the basis for the establishment in March 1985 of a joint federal-provincial Environmental Assessment Panel to review the Hibernia Development Project.

Hibernia Environmental Assessment Panel Mandate

Under the Terms of Reference issued to it by both the federal and provincial governments, the Panel was asked to assess the terms and conditions under which the project might proceed in a safe and environmentally acceptable manner. The review was to include production and transportation systems and major ancillary facilities associated with the project. Employment and industrial benefits expected from the project were to be examined along with the direct effects on the social and economic infrastructure in the communities. Not included in the Panel's mandate were questions of energy policy, jurisdiction, fiscal and management regimes, project economics or the division of revenues.

Receipt of Hibernia EIS

Mobil submitted its Environmental Impact Statement on May 15, 1985. Copies of the document or its summary were sent to people on the Panel's mailing list and placed in libraries, government offices and other convenient locations to assist members of the public in becoming familiar with the Environmental Impact Statement. Over 1500 copies of the EIS or its summary were distributed. Interested parties were invited to participate in the Panel review by providing written comments on the EIS by August 1, 1985. Notices were placed in newspapers and with other media in Newfoundland announcing the beginning of the EIS review. Details and dates of public information sessions, and the due date for written comments were similarly publicized.

The Panel retained the services of technical advisors to review specific aspects of the Environmental Impact Statement and supporting documents, to provide appraisals of the information presented in comparison with that requested in the guidelines, and to provide intervenors with responses to their questions.

Public Information Sessions

To give people an opportunity to ask questions about the project and to help them prepare comments on the EIS, the Environmental Assessment Review Panel held 12 public information sessions throughout the province in June 1985.

As a result of review of the EIS, the Panel received 22 submissions, which were made public in a compendium of comments, and distributed to all review participants in August 1985. The Panel reviewed the comments, and on August 15, 1985, requested further information from Mobil on icebergs, oil spills, loss of fishing areas, employment estimates and social issues. It also asked for information on waves, shuttle tanker traffic, sea-bed stability, monitoring, construction work camps, and a response to issues raised by review participants. Federal and provincial government departments were also asked to respond to issues raised relating to their responsibilities.

Intervenor Funding

In June, 1985, the Government of Newfoundland and Labrador announced a $50,000 Intervenor Funding Program to help groups prepare their submissions to the Hibernia Review Panel, which was to hold public hearings early in the Fall of 1985. Priority was given, in order of preference, to broadly based community oil and gas groups, individual organizations interested in oil and gas developments and Province-wide umbrella groups. Other factors considered in assessing applications included the area represented by the applicant, the level of organization and the internal resources of the applicant.

EIS Update/Supplementary Information

On August 15, 1985, Mobil submitted its EIS Update to the Panel. The Update described the preferred mode of development and highlighted the aspects which differed from the description contained in the EIS. On September 13, 1985, Mobil submitted a Supplementary Information volume of the EIS which was distributed to all review participants.

Public Hearings

Public Hearings were held during October 1985. The Panel heard sixty-six oral presentations and received 90 written submissions during the eleven days of hearings. The Provincial Government did not intervene at the hearings, but officials of the Petroleum Directorate were present throughout to respond to Panel requests for information concerning government policy and programs.

Panel Report

The Hibernia Environmental Assessment Review Panel presented its report to Government in December 1985. In keeping with its mandate the Panel identified measures to maximize the economic benefits and minimize environmental hazards and social disruption. The panel made a total of fifty recommendations, most of which were within the jurisdiction of the C-NOPB and were considered by the Board in reaching its decisions.

Canada-Newfoundland Offshore Petroleum Board - Decision 86.01

In June 1986, the C-NOPB submitted its decision on the Hibernia Benefits Plan and the Hibernia Development Plan to both the federal and provincial governments. Included in the information considered by the Board were the Environmental Impact Statement and the Hibernia Environmental Assessment Panel Report. Essentially, the Benefits and Development Plans were approved, subject to seventeen conditions.

In its Decision Report, the Canada-Newfoundland Offshore Petroleum Board noted that most of the Panel's recommendations on socio-economic matters fall outside the Board's direct responsibility. Those recommendations which were directed to other government departments or dealt with matters which are not within the Board's jurisdiction, were not addressed in the Decision Report. Most of these, however, are being addressed through the work of the Hibernia Construction Sites Environmental Management Committee in the preparation of an Environmental Protection Plan for Hibernia associated activities onshore. A separate Environmental Protection Plan governing the day to day offshore operations is to be prepared by the proponent and submitted to the Canada-Newfoundland Offshore Petroleum Board for approval as indicated in Condition 17 of the Board's approval of the Hibernia Benefits and Development Plans.

Hibernia Construction Sites Environmental Management Committee (HCSEMC)

In 1986, the Government of Newfoundland and Labrador established the Hibernia Construction Sites Environmental Management Committee, at the request of the Ministers of Environment and Development and Tourism, to prepare and monitor an environmental protection plan for each Hibernia related construction site and for the impacted area as a whole. Environmental protection plans are basically site planning documents used by a contractor to guide development and operation of selected projects with the intent to manage and thus minimize the consequences of potential negative environmental impacts. Government subsequently modified the structure of the Hibernia Construction Sites Environmental Management Committee to ensure attention to socio-economic issues.

Hibernia Project Co-ordinating Committee

In October 1988, the Government of Newfoundland and Labrador announced the creation of a new Hibernia Project Co-ordinating Committee, comprised of senior public servants, to provide a central focal point within Government for all follow-up on the project. The Committee mandate included, among other things, "co-ordinating action within Government Departments on social and environmental aspects of the Project".

A sub-committee of the Hibernia Project Co-ordinating Committee, the Hibernia Environmental and Social Impact Committee was established at the same time under the Chairmanship of the Deputy Minister of Environment and Lands to co-ordinate all aspects of social and environmental impacts of the Hibernia Project. The Hibernia Construction Sites Environmental Management Committee now effectively reports to the Hibernia Environmental and Social Impact Committee.

Community Interest Groups

Over the last several years, a number of petroleum related community interest groups have been formed in the Come-By-Chance area, some as the result of early public participation efforts by the Petroleum Directorate, some through the rural development movement and some on their own initiative. Among the more well known are The Concrete Platform Community Advisory Committee, The Come-By-Chance Area Regional Fishermen's Committee, The Come-By-Chance Area Businessmen's Association, and The Rural Oil Impact Monitoring Agency. The most recent to be formed is the Hibernia Impact Municipalities Association. This group followed largely from an indication from Government that a municipality-based organization would be the most appropriate type of organization to represent the area interests and would provide a focal point for future discussions with government and industry.

Environmental Protection Plan

In late June, 1989, Mobil presented to the Hibernia Construction Sites Environmental Management Committee, draft interim environmental and protection plans covering the first six months of the Hibernia Gravity Based Structure construction plan at the Placentia Bay site.

Shortly after the draft interim environmental protection plans were received and an evaluation process initiated, Mobil indicated that it was considering an alternative site to that in Placentia Bay. The new site as we now know is Great Mosquito Cove in Bull Arm, Trinity Bay. In addition to being a better site from a technical and economic perspective, the new site involves considerably less conflict with fishing operations.

In April, 1990, Mobil presented Government new draft interim environmental protection plans for the Trinity Bay Site. These interim Environmental Protection Plans are still being evaluated by Government.

MOUs - Fisheries - Environment

In a mega-project, such as Hibernia, a large number of federal and provincial departments and agencies will continue to have ongoing and sometimes overlapping responsibilities for protection of the environment. This is clearly recognized in Section 46 of the Canada-Newfoundland Atlantic Accord Implementation Acts, which empowers the

C-NOPB to enter into Memoranda of Understanding, to ensure effective coordination and avoid duplication of work and activities. Included in the agreements already put in place are Memoranda of Understanding on the Provision of Environmental Services and on The Protection of Fisheries and The Provision of Ocean Related Services. These Memoranda Of Understanding provide for lead agency status for the C-NOPB with appropriate departments and agencies of the federal and provincial governments having principal advisory or support responsibilities. As a result of these two Memoranda of Understanding, a Newfoundland Environmental Advisory Committee has been established to:

(i) provide a forum in which the Board may receive advice and information concerning environmental and fisheries matters relevant to oil and gas activities in the Newfoundland Offshore Area;

(ii) facilitate the exchange of information among the parties; and

(iii) promote a coordinated approach to the resolution of environmental issues.

An important responsibility of the Newfoundland Environmental Advisory Committee will be to provide advice respecting the Environmental Protection Plan, including an effects monitoring regime, governing the day-to-day operations at the Hibernia site.

Public Access to Information

An important component of any environmental/socio-economic impact assessment process is the provision of information about development projects not only before activities actually begin but throughout their lives. As I indicated earlier, public information and input was a cornerstone of Governments' early community relations initiatives and this has been carried through via the Hibernia public information sessions and panel review. In addition, the Environmental Protection Plans being developed will incorporate public information and public liaison components.

Conclusion

In conclusion, I have attempted to provide a broad overview of the environmental assessment process as it applies to the Hibernia project. It is indeed a process - a process that will continue until the last drop of Hibernia oil is extracted and marketed. While I have tried to simplify the process, it understandably reflects a complex web of inter-relationships and overlapping responsibilities. Concern about the environment has never been more prominent than it is today. I think you will agree that the environmental assessment process, which I have outlined, is indeed a full and comprehensive one, and underscores the commitment of both the federal and provincial governments to ensuring that petroleum development proceeds in an environmentally acceptable manner.

SPEAKER : **JAN ASKE BORRESEN**

COMPANY : **MINISTRY OF PETROLEUM AND ENERGY**

LOCATION: **OLSO, NORWAY**

TOPIC : **ENVIRONMENTAL IMPACT ASSESSMENT AND OFFSHORE PETROLEUM ACTIVITIES IN NORWAY**

BIOGRAPHY: Mr. Borresen has a master's degree in meteorology from the University of Bergen. Head of the Environmental Data Centre, Norwegian Meteorological Institute. At present, he is adviser to the Ministry of Petroleum and Energy and in charge of the environmental impact study programmes. Mr. Borresen has published "Wind Atlas for the North Sea and Norwegian Sea", Oslo University press, 1987. He has developed several computer systems for PC on criteria for maritime operations and extreme value analyses for design.

ABSTRACT

ENVIRONMENTAL IMPACT ASSESSMENT AND OFFSHORE PETROLEUM ACTIVITIES IN NORWAY, STATUS AND RESULTS

SUMMARY

In 1963, Norway proclaimed sovereignty over the continental shelf. Two years later, Norway and the UK signed an agreement delimiting the continental shelf according to the median line, and only one month afterwards, in April 1965, the first production licences were granted in Norway. Since then, we have witnessed a modern industrial adventure of vast proportions.

In 1990, production is currently running at 1.76 million barrels of oil a day; there is a voluntary 5% cutback from the theoretical maximum, 1.81 million barrels/day. Total production in 1989 was 103.6 million tons of oil equivalents, 74.9 million tons oil and 28.4 billion tons gas. Norway's domestic consumption is 9.5 million tons of oil; all gas is exported.

Development from 1971 to 1985: the technical period
We may well wonder why, with 20 fields on stream, 9 under development, and 16 still to come, the environmental impact of petroleum activity is only now being considered before new sectors of the continental shelf are opened up.

The reasons are twofold: partly related to the speed of development and technical challenges met during the build-up of the industry, and partly to the growing awareness of environmental problems. This is clearly reflected in the development of petroleum legislation. Some milestones from the start in 1971 up to 1985 are:

1976 Regulations on the instrumentation of fixed platforms
1977 Act relating to worker protection and the working

environment
1981 Pollution control Act
1985 Regulations concerning internal control by the licensee
1985 Act pertaining to petroleum activity

Two serious accidents have also influenced the petroleum scene in Norway.

1977 Ekofisk blow-out, 20 000 tons of oil spilt in one week.
1980 Capsize of the flotell "Alexander Kielland", 123 drowned.

As a result of these accidents, 1.7 thousand million dollars have been spent on oil pollution control equipment. All those visiting or working on offshore installations must follow a safety course of at least 14 day's duration.

Development 1985-1990: the environmental age

Section 7 of the 1985 Act pertaining to petroleum activity requires an environmental impact assessment to be made before an area is opened up for petroleum activities. It must include an assessment of environmental impacts and the risk of pollution as well as economic and social consequences for other trade and industry and regional effects. Local authorities, central trade organizations and the general public must be notified when the opening of new areas is under consideration.

Work on EIAs is coordinated by the Ministry of Petroleum and Energy. An interministerial Working Group for EIA of petroleum activities has been established, and acts as an advisory body for the Ministry.

In 1988, the Ministry of Petroleum and Energy presented an Environmental Impact Statement (EIS) for the Barents Sea South. The area extends from the coast of Troms and Finnmark counties to latitude 74 deg 30 minutes north. It includes breeding and growth areas for commercially important fish species and substantial populations of seabirds and marine mammals. The EIS assesses possible ecological and social consequences of petroleum activities in the area. The organization of the work and the main results will be presented.

Environmental Impact Assessments are under preparation or planned for areas which may be opened for petroleum exploitation in the longer term. These are:

- Mid-Norwegian Continental Shelf
- North Sea East - Skagerrak
- The Vering Plateau
- The Barents Sea North

The problems which are in focus today will be discussed.

ENVIRONMENTAL IMPACT ASSESSMENT AND OFFSHORE PETROLEUM ACTIVITIES IN NORWAY, STATUS AND RESULTS

1. What progress has been made so far?

The Norwegian petroleum Act requires impact assessments to be made in two steps: before new areas are opened for petroleum exploration, and before any discoveries are developed. In this contribution, I shall concentrate on the impact assessments before an area is opened, which are the responsibility of the Ministry of Petroleum and Energy.

In 1988, the Ministry of Petroleum and Energy presented the impact assessment for the Barents Sea South. This was the first time a comprehensive impact assessment was made before the opening of a major sector of the continental shelf. The assessment programme ran for three years, and a number of expert groups were involved in studies of possible positive and negative consequences of petroleum activities on this part of the Norwegian shelf.

In 1989 work started on impact assessments for several new areas: the Skagerrak, the mid-Norwegian continental shelf, the Vøring Plateau, and the Barents Sea North.

Responsibility for organizing impact assessments is delegated to the Working Group for Impact Assessment of Petroleum Activities (the Working Group). The members of the Working Group are drawn from the Ministry of Fisheries, the Ministry of Local Government and Labour, and their subordinate institutions. The petroleum industry also has one representative in the group. The Working Group is an advisory organ to the Ministry of Petroleum and Energy.

The Working Group drew up the programme for the impact assessment of the Barents Sea South. The institutions submitted proposals for projects and data collection programmes. The Working Group evaluated the proposals, and recommended to the Ministry of Petroleum and Energy which of the proposals should be carried out. Progress was followed up by steering committees.

In hindsight, this organization form appears to have given many people the impression that the Working Group was a source of funds for all types of projects which might be relevant to future petroleum activities in the Barents Sea. This was probably because the objectives of an impact assessment were not adequately understood, and because it was not clearly defined which effects should be investigated. I believe that the first factor was most important. At the time, the requirement for a comprehensive impact assessment was new and not embodied in other Norwegian laws.

We have chosen another organization model for the new impact assessment programmes, for the Skagerrak and the Mid-Norwegian shelf. The process starts with a brain-storming meeting among researchers and administrators lasting 1 1/2 days. From the ideas and questions formulated at this meeting, a small group of 3 people writes a proposal for an impact assessment programme. This programme is sent on an extended hearing to local communities and research institutions. Based on the comments received, the Working Group decides which issues are to be given priority and formulates the framework for the particular impact assessment. Once this is done, relevant research centres will be invited to draw up project proposals. The Working Group considers the proposals it receives, and recommends to the Ministry of Petroleum and Energy which of them should be carried out.

2. What results have we obtained to date?

Conflict indicator for seabirds

New and improved methods have been developed for assessing several aspects of the consequences of petroleum activities. During the Barents Sea South programme, methods were developed for assessing the severity of the conflict between oil and seabirds and potential conflicts between the petroleum industry and fisheries. Both sets of conflict indicators are based on standardized guidelines which can be used to assess the consequences of a spill.

The assessment model developed for seabirds makes it possible to estimate a relative vulnerability index for species which may be affected by oil spills from proposed activities. A distinction is made between an index for immediate effects and one for long-term effects. These indices measure vulnerability to oil and its seasonal variation both at the individual level, i.e. immediate effects, and at the population level, i.e. long-term effects. This work allowed us to identify and grade the potentially most vulnerable species.

Conflict indicators for fishing activities

Conflict indicators for the fisheries were developed to analyze the spatial consequences of petroleum activities. The emphasis was on clarifying where conflicts may arise between the petroleum industry and fisheries, and geographical variations in conflicts. For this type of analysis, the whole area under consideration was divided up into grids where the squares were 15' north/ south by 1° east/west (three oil blocks). Within this grid, potential area conflicts were estimated for each type of fishing gear. The indicators were weighted prices for different fish species during a five-year period for the total area, against the price for the catch within each grid.

This type of weighting did not take account of the fact that the area loss to petroleum activities will not be the same for all fisheries. In general, larger vessels will more easily be able to use alternative fishing grounds than smaller vessels with a more limited radius of action. The larger ocean fishing fleet was assigned only 1/5 of the value on which the general conflict indicator was based. The results emphasize the importance of the coastal fisheries in the areas affected.

Distribution of fish eggs and larvae in space and time

The development of the offshore petroleum industry has made it necessary to know more about where and when fish resources are most vulnerable, and how severe the damage will be if a spill occurs. The Egg and Larvae Programme at the Institute of Marine Research (the HELP programme) was therefore started in 1986. This is a five-year research programme which is intended to provide more information on how fish eggs and larvae are distributed in time and space, and on the food organisms for fish larvae. The programme has been financed by the Ministry of Fisheries, but was closely associated with the impact assessment programme run by the Ministry of Petroleum and Energy.

The HELP programme and projects financed by the impact assessment studies have given us a great deal of new information about:

- the vulnerability of fish eggs and larvae to various concentrations of oil
- which development stages are most critical
- which times of year are most critical for different species and
- the horizontal and vertical distribution of these species.

For example, we have found that eggs and larvae of cod (under 20 mm) and saithe are very sensitive to oil pollution. Capelin eggs and larvae seem to be hardier, while herring eggs and larvae are quite tolerant to oil pollution. These results, together with new information on the distribution of vulnerable resources during the year, were valuable in drawing up the impact assessment for the Barents Sea South.

Based on this information, the Norwegian Government introduced geographical restrictions and banned drilling in certain months of the year in some areas.

Conflict zones

Not all conflicts could be quantified. The impact assessment for the Barents Sea South therefore concluded that the exploration area should be divided into four zones graded according to vulnerability:

- the coastal zone
- the egg and larvae zone
- the Arctic zone and
- the open sea

The coastal zone is a 20-50 km wide belt along the coast of Troms and Finnmark counties. Within this zone, there are rich biological resources - fish, seabirds and mammals. There are coastal fisheries, fish farms and settlements. Recreation, tourism, and other trades and industries are also found in the area. The petroleum industry must exercise particular caution in this area, and special safety precautions will be required.

The egg and larvae zone is defined as the area where there are large concentrations of vulnerable cod eggs and larvae at certain times of the year. This zone covers the area south of 71°30' N and west of a line from Bear Island to the North Cape. It was in this zone that restrictions were imposed on petroleum exploration for certain times of the year.

The Arctic zone was defined as a belt around Bear Island where there are large seabird colonies, and the very productive area near the ice edge, which attracts feeding fish, seabirds, and marine mammals. Satisfactory oil pollution control techniques for this area have not yet been developed, and measures to mitigate harmful effects must be further investigated.

The open sea was defined as the remainder of the assessement area. Here, we do not find dense concentrations of vulnerable species which may be affected by petroleum activities.

The above zones have been helpful to the authorities when considering whether or not to open a specific area for exploratory drilling, and particularly when setting conditions for drilling in different parts of the Barents Sea South.

3. Future issues

Of concern in Norway at the moment are problems related to petroleum activity on the Norwegian shelf in general, and those which are directly related to the Barents Sea North assessment area. Two issues in the first group can be mentioned:

- environmental effects of continuous discharges from the petroleum industry, and
- the effects of seismic investigations on marine life.

The most important questions related to the Barents Sea North will be:

- The behaviour, properties and degradation of oil in ice, including oil at the ice edge.
- Conflicts with vulnerable marine life if an oil spill occurs, with emphasis on ecological relationships in the area.
- The limitations of oil pollution control services in ice-infested areas.

The probability of oil pollution from a blow-out is relatively low; in contrast, continual discharges (operative discharges) will certainly occur both in the exploratory phase and the production phase. The major problems arise from discharges of drill cuttings and chemicals to water.

The State Pollution Control Authority monitors the environment around the platforms annually to ensure that oil companies comply with the limits of the discharge permits.

Until now, emphasis has been on monitoring sediments, benthos, and fish resources around the platforms.

Monitoring programmes become even more important as the industry moves northwards, and certain new issues arise. The northern seas have a very high biological production, and are much more sensitive to oil spills than the areas further south. There are often large concentrations of seabirds near the ice edge which are vulnerable to even small oil spills. International rules for discharges in Arctic areas are at present being drawn up; in practice, these mean that activities in the northernmost areas will be significantly limited and subject to strict regulations.

Seismic surveying

The relationship between seismic investigations and fisheries has received attention for a number of years. The main aim has been to prevent area conflicts between seismic vessels and fishing vessels. The various arrangements made and steps taken to prevent this can be discussed and certainly be improved.

However, it is now claimed in several quarters that the resource crisis in the Barents Sea, and the resultant problems in North Norway, have been caused by extensive seismic shooting in this area. There have been demands for seismic investigations to be stopped until it has been proved that they do not harm fish.

The Institute of Marine Research made some investigations in 1985. These showed that fish fry very close to (within 2 m of) a water cannon were killed, while such damage was not shown if an airgun was used.

Despite the fact that earlier investigations provide no evidence that seismic investigations harm fish, the authorities are prepared to continue their investigations in order to remove any uncertainty.

Barents Sea North

The greatest challenges facing us are related to the impact assessment which will be started for the Barents Sea North, where large areas of the sea are ice-infested for parts of the year.

It is important to consider the Barents Sea as a whole, where consequences for one part of the ecological system may indirectly affect many other species. An oil spill which reduces the amount of zooplankton can limit the food available for adult fish, seabirds and seals in the area of the impact assessment. A reduction in the food supply in one sector of this area is not easily compensated by movements of the migrating animals to neighbouring areas.

Many research projects are already being done in the area. Work on vulnerable marine organisms, marine mammals and seabirds will therefore be continued for use in drawing up an impact assessment.

Knowledge of the oceanographical and meteorological conditions is a central aspect of an impact assessment for the Barents Sea North. The physical environment sets the framework for any future activity, including oil pollution control services. The data bases for currents, ice drift, ice cover and breakup of ice must be improved as necessary to carry out a satisfactory impact assessment for the Barents Sea North.

Oil drift models have been developed in connection with earlier impact assessments. These are based on the historical weather data available and estimates of the current in the relevant areas. Oil drift models, together with information on the marine climate, are used as the basis for analyzing possible conflicts between oil spills and vulnerable resources. In the models developed so far, the ice edge has generally been regarded as a barrier to oil drift. However, a more dynamic approach must be used in order to combat spills or collect oil in ice-infested waters. The consequences of oil spills which are trapped in ice for long periods of time must also be evaluated. Knowledge of the behaviour, properties and degradation of oil in ice, including oil at the ice edge, is crucial for decisions on petroleum activities in this area.

The oil spill control services are intended to give equal protection to the ice environment and to the environment along the coast. It is therefore an important goal to develop new oil spill control technology for ice-infested waters and methods for using existing technology under the harsh climatic conditions found in our northernmost waters.

The Barents Sea South is practically free of heavy sea ice all year round. The problem of oil spills in ice has only recently become current in our country as we move north with our oil exploration activities. We therefore look to Canada and Canadian research institutions and companies for cooperation. We wish to draw on Canadian expertise to work on these problems together.

Acknowledgement

The author would like to thank cand. oecon. Martin Ivar Aaserød for all help in preparing this manuscript.

Information and references to methods and research programmes can be obtained from:

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SPEAKER : **DANIEL P. O'BRIEN, C.R.S.P.**

COMPANY : **SEASCAPE SYSTEMS LIMITED**

LOCATION: **ST. JOHN'S, NEWFOUNDLAND**

TOPIC : **OFFSHORE EVACUATION SYSTEMS**

BIOGRAPHY: A former diver and submersible pilot, Mr. O'Brien has worked extensively in the Offshore Petroleum Industry in Canada, Central and South America, Africa and Europe. It was during 1981, while working on the "Ocean Ranger" that he experienced the complications of evacuating a rig. As a result of this encounter, he invented the Computer-Aided System of Evacuation (C.A.S.E.). In 1985, Mr. O'Brien incorporated Seascape Systems Ltd. to research and develop this device. He holds the accreditation of the "Canadian Registered Safety Professional", and is a Member of the "Canadian Society of Safety Engineering". He has worked as an instructor in Offshore Survival Training at the Marine Institute, and has sat with several Maritime Safety Committees in Canada. He has, also, presented a number of papers to International Conferences both here and abroad.

ABSTRACT

"OFFSHORE EVACUATION SYSTEMS"

The Offshore Petroleum Industry and the technology associated with it have developed rapidly in the last twenty years. Both Modus and production units in use today have evolved into sophisticated structures, designed and built to withstand the severest of environmental conditions and equipped to drill in deep waters. The industry has arrived at this stage by incorporating in its various aspects the use of advanced technology. High tech devices are integral, for example, to the collection and evaluation of geological and seismic data, to the operation of dynamically positioned structures, and to methods of well control.

In spite of these advances, accidents requiring evacuation from rigs and platforms still occur. In addition, the environmental conditions off Eastern Canada and the North Sea are especially severe, with extremes of wind and wave, and a frequency of storms found in few other areas of the world where offshore activity is conducted. These conditions often preclude the use of helicopters or standby vessels as evacuation vehicles, and crews are left with the only remaining option: evacuation in the Facility's totally enclosed motor propelled survival craft (TEMPSC).

The design of TEMPSC and of their launching systems has not always kept pace with the development of the technology applied in other areas of the offshore industry. Abandonment systems presently utilized in the Offshore Petroleum Industry are no more than adaptations of equipment employed on conventional ships.

Experience has frequently proven the TEMPSC, as it currently exists on offshore structures, inadequate as a successful evacuation method. Recent accidents involving evacuations from Facilities, such as the structural failure of the Alendander L. Kielland in 1980, the capsize of the Ocean Ranger in 1982, the blowout at the Enchova Platform off Brazil in 1984 and the devastation of Piper Alpha, all involved loss of life which can be attributed directly to the inadequacies of the evacuation systems. These unsuccessful evacuations demonstrated the difficulties involved in escaping to and launching a TEMPSC using current equipment and methods. Problems were encountered in keeping the TEMPSC from being smashed by impact against rig structures, either during lowering or immediately after reaching sea level; problems also occurred when release mechanisms connecting the TEMPSC to the falls used to lower them to the sea, failed.

OFFSHORE EVACUATION SYSTEMS

The offshore petroleum industry and the technology associated with it have developed rapidly over the last twenty years. The necessity for more efficient structural designs became more apparent as the industry began drilling in deeper waters and in areas which experience severe winds and seas.

One of the most common effective MODU's (Mobile Offshore Drilling Units) used offshore today is the semi-submersible drilling rig. The semi-submersible is basically a barge or deck supported on a series of vertical columns or legs which in turn are situated above two pontoons. These components are generally secured by diagonal braces and transverse tubulars which run between each pair of legs. The point of attachment of the braces and tubulars is just above pontoon level.

These MODU's are quite high, and the distance from the keel to the deck can range from 40 - 50 meters.

Semi-submersibles have three drafts:

1) Transit draft.
2) Drilling draft.
3) Survival draft.

A rig is ballasted to survival draft when it is likely to be under adverse weather or sea conditions. At survival draft the distance from the waterline to the deck can be as much as 25 meters. As the embarkation area for evacuation systems is normally on the main deck, this is also the distance lifeboats will have to travel to reach the water.

On the topside of a drilling unit, not much deck area is wasted. Due to the layout of the superstructure and the drilling equipment, the deck can be a rather confusing place to navigate, even under the best of conditions. In complete darkness or under heavy seas, trying to make one's way from the derrick floor or accommodation area to the embarkation station can be a difficult undertaking. Survival craft are generally positioned at the bow and stern, in cantilevered davits and pointing away from the rig. This is done to comply with Coast Guard Regulations which also require total survival craft capacity to equal 200% of the total complement of personnel on board, with 100% capacity on opposite ends of the rig. Grandfather clauses unfortunately permit older rigs to maintain boats similar to those used on the "Ocean Ranger" parallel to the deck.

Totally-enclosed-motor-propelled survival capsules - or TEMPSC, for short, sit in a static davit and are held in place by single point or tandem wire falls leading from a centrifugal winch. The winch can be found sitting above the davit. The wire fall and its bull ring are connected to the hook assembly situated on the top of the craft. When the brake is released, the winch feeds out the cable at a constant speed.

There are two types of release mechanisms generally found on these conventional lifeboat systems:

1) Offload release mechanisms can be activated while the boat is still suspended in mid-air, but will not release until the boat is waterborne and the weight comes off the hook. This system has limited success when strong currents or heavy seas place a strain on the hook, thereby preventing its release. When this happens, the TEMPSC hangs there and is likely to make contact with the rig. This problem was noted during evacuation of the "ALEXANDER KIELLAND", in 1980, when a total of 123 people died.

2) Onload release mechanisms will release the wire fall whenever activated. The problem here is that under times of stress or panic, persons may misjudge the distance from the surface of the water and release the TEMPSC prematurely. This was an occurrence on the "ENCHOVA" platform off Brazil in 1984, in which 36 people were killed and 19 more were seriously injured.

In 1982, a 1:40 scale model of the drilling rig "OCEAN RANGER" was built and tested in Trondheim, Norway for the "Royal Commission on the Ocean Ranger Marine Disaster". An identical model was built and tested at the National Research Council's Hydraulics Lab in Ottawa. The rig models were tested at various angles of inclination under adverse sea states, in an attempt to re-create the situation of the "Ocean Ranger" which claimed 84 lives in February, 1982.

A diagram (Fig. 1) included in the Ocean Ranger Report One was drawn prior to the sinking of the Ocean Ranger. It shows the rig positioned with a nose-down attitude, and the angle of the trim indicated between the vertical column and the perpendicular line to the static waterline is 12 degrees. In this diagram the rig is at survival draft, and the stern of the pontoons are protruding through the surface of the water. A little orange blurb at the top represents the TEMPSC being lowered conventionally by a wire fall and coming in contact with the transverse girder.

Immediately prior to the abandonment of the Ocean Ranger on the morning of February 15, 1982, the Mobil Representative on board informed his counterpart on the SEDCO 706 that the rig had a trim of 15 degrees to the bow. And, of course, on that February morning the seas were far from static; they were quite severe.

At this trim, the port bow was completely awash. The massive mooring winches were completely submerged, and located about 20 feet on the other side of these was the survival craft. It's difficult to imagine anyone reaching that boat with such a torrent of water on deck. Also, with such vicious seas coupled with high winds, the rig's crew had little chance of successfully launching the TEMPSC lowered on wire falls. No doubt, they swung or pendulumed quite violently and beat against the rig. When the lower part of the MODU was reached, they may well have been corralled inside the transverse tubulars or, at the very least, been repeatedly smashed into them.

Semi-Submersibles, however, are not the only offshore structures with evacuation problems. The steel jacket platform is a typical structure used for production and is found in the Gulf of Mexico, the North Sea, and other areas around the world. One such production platform made history in 1988 when it became the largest disaster in offshore petroleum history. Its name is the "Piper Alpha".

"Piper Alpha" was an installation located 125 miles north east of Aberdeen. Its purpose was to separate oil and gas from water before transporting it by pipeline to land. On July 6, 1988, at 2 minutes past 10 p.m., a huge explosion occurred causing extensive damage to the process and control systems. At this point the structure was engulfed in a massive fire with huge clouds of black smoke covering 90% of the platform. Thirty-three minutes later it is known that at least 100 persons were still alive in the accommodation module. A transmission was received by Tharos, an adjacent semi-submersible, requesting it to rescue them with the aid of its hydraulic gangway. Tharos, the semi-submersible, however was unable to come within 500 meters of the "Piper Alpha" for fear of being hit by one of the enormous re-occurring explosions.

The people trapped inside by the radiant heat and thick smoke were unable to find a safe means of egress to the lifeboats. Two hours after the first explosion the accommodation module fell into the sea. This tragedy resulted in the loss of 167 lives. Miraculously, 61 people survived this holocaust by sliding down hoses or jumping directly into the sea from heights of 68, 100, 133, and 175 feet! This, however, should never be considered the ultimate means of escape.

One month after this disaster, the "Ocean Odyssey", an identical rig to the "Ocean Ranger", experienced a blow out and burned from the waterline up. In this incident, the radio operator died. Some of the crew narrowly escaped by TEMPSC, while others, including the Captain and ballast control operator, were forced to jump into the fiery sea.

A new design of offshore production facility which has been developed and utilized in the Norwegian sector of the North Sea is the gravity-based platform, or GBS. These structures incorporate a number of safety features, including a blast-proof wall which separates the accommodation modules from the process area or "Hot Zone". Its purpose is to offer protection to the occupants of the accommodation module. This, unfortunately represents only 60% of the complement on board, because the other 40% will be working on the hot side of the blast-wall in the process area. Although no disasters have occurred as yet on GBS's, there have been a number of gas leaks reported which were successfully brought under control.

If a GBS were to explode and burn tomorrow, it would have the distinction of being the first structure of that design to do so, but it would most certainly not be the first offshore structure to be destroyed. Reports made available by the Worldwide Offshore Data Bank and other sources reveal that between the years of 1970 and 1990, there were 123 offshore rigs and installations destroyed with the loss of over 1,300 lives. Sixty percent of these losses have occurred since 1980 on facilities aged from 5 years to 13 years. These huge losses of life may be expected to continue for several reasons:

1) Because of the impact of lower oil prices in recent years, offshore operators openly admit reduced expenditures on maintenance of offshore structures.
2) When the oil industry went offshore, they built platforms and rigs specific to their special needs. They did not, however, design evacuation systems for use on these structures. They simply adapted conventional life saving equipment from traditionally hull-shaped vessels.
3) Studies done by consulting firms such as Technica of London, England show that in actual disasters under adverse weather conditions, conventional systems fail 88% of the time with the loss of life equivalent to the same percentage. Using a computer risk model, the failure rate is 96%.

These alarming statistics have inspired the further action of three highly regarded organizations which are deeply involved in the offshore industry. The Government of Great Britain through its Departments of Energy and Transport has notified industry of its intention to greatly enhance the means of evacuation of personnel from offshore structures. Special emphasis has been placed on evacuation routes and the launching methods of TEMPSC's. This plan is outlined in their "Statement of Intent, Life Saving Appliances on Offshore Installations, August 1989".

In addition to this initiative, the International Maritime Organization has recently approved amendments to its MODU Code which are to become effective May 1st, 1991. These changes refer directly to the stability criteria of such MODU's. The maximum allowable angle of inclination of a MODU in a flooded condition has increased from 15 degrees to 25 degrees. All emergency equipment including life saving appliances will be required to function at these increased angles.

Also, the Centre for Offshore and Remote Medicine of the Health Sciences Complex, Memorial University of Newfoundland, will soon commence a very detailed study of the evacuation of critically injured personnel from offshore facilities. Accident scenarios such as the "Ocean Ranger" and "Piper Alpha" tragedies will be investigated to determine the numbers and types of injuries.

Cognizant of the high failure rate of existing equipment, some governments have jointly undertaken with industry a number of initiatives to solve this problem of evacuating offshore structures. The most intriguing thus far has been the free-fall lifeboat. There are basically two generations of free-fall lifeboats developed to date. The first is a craft designed to launch on a trajectory from ships and floating structures. These are made of G.R.P., aluminium, and steel. The second generation is constructed of steel, intended for use on the higher decks of gravity based platforms. Positioned at an angle in its davits, the bow and stern are respectively 28 meters and 33 meters above the water. When launched, the T.E.M.P.S.C. drops vertically at a speed of 40 km per hour. Upon impact, the boat completely submerges, rotates on its axis and due to its inherent buoyancy shoots to the surface on a direction away from the platform.

When the vertical freefall boat surfaces the evacuees find themselves resting on their backs. In order to withstand the excessive "G" forces (8 G's / .5 second) incurred during free-fall, it is necessary to place the person in a special seat and secure them with a four-point harness around the torso and a velcro strap around the head.

These craft have been developed mainly in Holland and Norway and can be found on structures and rigs operating in the Dutch and Norwegian sectors of the North Sea. These devices, although used frequently in training schools have not been deployed during the supreme tests. This leaves a few questions unanswered. The most notable are the psychological preparedness of evacuees to use this equipment under stress; the evacuation of critically injured personnel whom must never be bent in dangerous positions, and the possibility of seasick individuals (eventually all) aspirating their own vomit while in the prone position. It should, also, be pointed out that investigations of offshore evacuations have consistently shown evidence of pre-mature launch of life boats. What does this mean, if a person is not properly positioned in a freefall lifeboat?

There have been a number of other devices which have surfaced in recent years. Some incorporate articulated arms and hydraulic booms which provide modest advances in launching survival capsules.

Other operators chose to simply extend the equipment out from the rig to avoid collision while the boat is being lowered. This greatly impedes rig performance and has a negative effect on the variable deckload capacity.

To design the ultimate evacuation system is an impossible task. One might say that the only sure way of conserving life is not to go offshore at all. But that is not a realistic option. We could also consider backfilling the Grand Banks, for example, and paving it, but some may consider that to be somewhat unreasonable. The next best thing is to provide a self-contained emergency system which will allow these workers - - who incidentally are also the rescuers - - to save their own lives. And, if you were to ask an experienced mariner what he would prefer, he would say that he would want to get on the biggest thing that he could find that floats. The TEMPSC undoubtedly best fits that description, provided it can be launched safely from the stricken rig or structure.

There is one up and coming concept which has proven to be quite promising. This concept is of local origin and is called the Computer-Aided System of Evacuation, or the CASE System.

The primary structural components of CASE consist of a deployment arm; a TEMPSC providing capacity for up to 150 persons; an on-board computer; and an enclosed passageway.

The bottom of the deployment arm is supported at two pivot points on an existing transverse girder at pontoon level on a semi-submersible, either at the bow or at the stern. The system may also be adapted for installation on steel jackets and large hulled vessels, such as very large crude carriers. It is proposed that one CASE unit be installed at both the bow and the stern, so that the regulatory requirement for 200% capacity lifeboats is satisfied. The deployment arm extends up towards deck level where a cradle at the peak of the deployment arm supports a single TEMPSC with sufficient capacity. The TEMPSC is installed to point away from the rig, and its entry hatch at the stern is air-sealed against an enclosed passageway leading from the rig. The cradle supporting the TEMPSC is mechanically pivoted so that during a launch, zero degrees trim may be maintained at all times. The TEMPSC, the cradle, and the deployment arm are held in place by cables extending from a centrifugal winch on the deck of the rig to a point on the upper arm.

The operation procedure for the CASE System is quite simple. In an emergency the crew musters in a strategic area within the superstructure. An air tight door is opened leading into one end of the enclosed passageway which is sealed at the other end against the stern of the TEMPSC. The evacuees pass through this protected route and on entering the TEMPSC the hatches are closed. At this point, the crew has completed the first important step in evacuating a rig and that is reaching the life boat without being exposed to the dangers which threaten to kill them.

When the decision has been made to launch, the winch brake is activated from inside the boat. The deployment arm carrying the TEMPSC now arcs out and down to the water placing the survival craft at a maximum distance from the stricken structure (see Fig. 2). Upon reaching the water, the survival craft floats out of the cradle, and the arm and cradle continue to swing through the water and disappear beneath the surface. A successful evacuation has been completed.

Over the last five years considerable research and development has been carried out on the CASE System. This has included the wave-tank testing of three models. The first two, on 1:75 and 1:30 scale, were tested in 33 meter and 20 meter seas respectively. The rig models fitted with the CASE model were positioned at combined inclinations of 20° high heel and 20° list in orientations of head, beam and following seas. A third model on a scale of 1:15 was tested in 1989 utilizing a Jonswap wave spectrum. It was subjected to a maximum wave height of 14 meters combined with 40 knot winds. This model was orientated in head, quartering and beam seas with combined angles of inclination of 20° high heel and 15° list. A total of 116 runs on this third model provided a substantial amount of data, including rates of deceleration (.5 G's / .5 second) and impact forces (see Table 1.). Other instrumentation measured tensile and compression loads on the arm and forces acting on the deployment cable. All tests clearly demonstrated the System's ability to successfully launch the TEMPSC's under all conditions. This extensive testing program was carried out by the Institute for Marine Dynamics, National Research Council of Canada at the request of the Government of Newfoundland and Labrador.

As was indicated earlier in this paper, the development of the ultimate evacuation system is indeed difficult. None has yet surfaced. The Computer-Aided System of Evacuation was designed and tested to address all possible known scenarios which have already occurred in actual incidents. The most notable are those which involved the "Alexander Kielland" and "Ocean Ranger" semi-submersibles, and the "Enchova" and "Piper alpha" production platforms. The testing described above was carried out to simulate these incidents.

It should be mentioned at this point that a prototype of CASE will be constructed this year. Testing will involve inclining the system in two planes at angles up to 25°. Further attention will be paid to the enclosed passageway and its seal with the stern of the TEMPSC. The outcome of this testing will offer conclusive results that the CASE system offers the best opportunity of survival for offshore personnel. It is intended also, to clearly demonstrate to industry and regulators alike that this system offers the following advantages:

1. simplicity of operation;

2. psychological acceptance to offshore personnel;

3. the ability to evacuate critically injured individuals in stokes litters and stretchers, due to low impact and deceleration forces incurred during launch;

4. no necessity to cantilever TEMPSC out from barge or deck to achieve clearance on a high trim, therefore allowing greater accessibility of "enclosed passageway" to TEMPSC;

5. maximum protection against radiant heat, smoke and all poisonous gases;

6. elimination of the need for wire-fall, release mechanisms, and the resultant penduluming and smashing of TEMPSC into structures during launch;

7. placement of the TEMPSC a considerable distance from the structure when waterborne;

8. cost competitiveness per capita basis due to its ability to launch larger or multiple numbers of TEMPSCs;

9. insignificant effects on the center of gravity on floating systems because the load is mounted on the lower part of a unit, and provides minimal incremental weight over conventional launch systems, which, in turn imposes little or no deck load penalty on floaters or fixed structures; and,

10. possibility of retrofitting without significant modification to most structures or floating units.

Unfortunately, we find ourselves at present in a situation where persons working in the offshore do not have the same high level of safety that workers in other industries enjoy. This is unconscionable. In 1990 it should be considered a fundamental right that people working on rigs and platforms have the best safety equipment that present technology can provide. The Computer-Aided System of Evacuation meets these criteria.

Before closing, I would like to express my sincere pleasure in having presented this paper to you. I also would like to say thank you to the Newfoundland Ocean Industries Association for having provided me with the opportunity to do so.

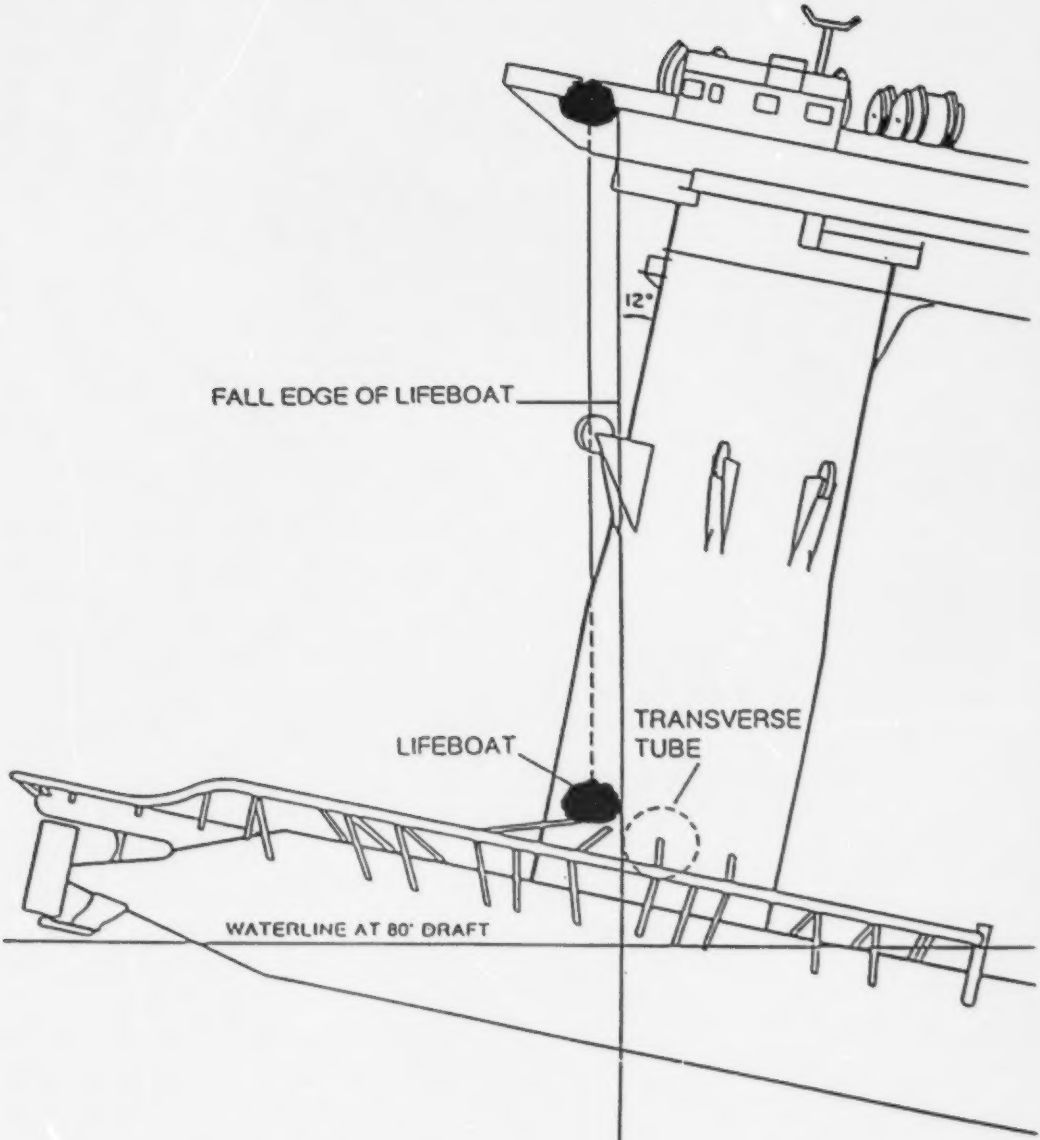

12°
FALL EDGE OF LIFEBOAT
TRANSVERSE TUBE
LIFEBOAT
WATERLINE AT 80' DRAFT

FIGURE 1.

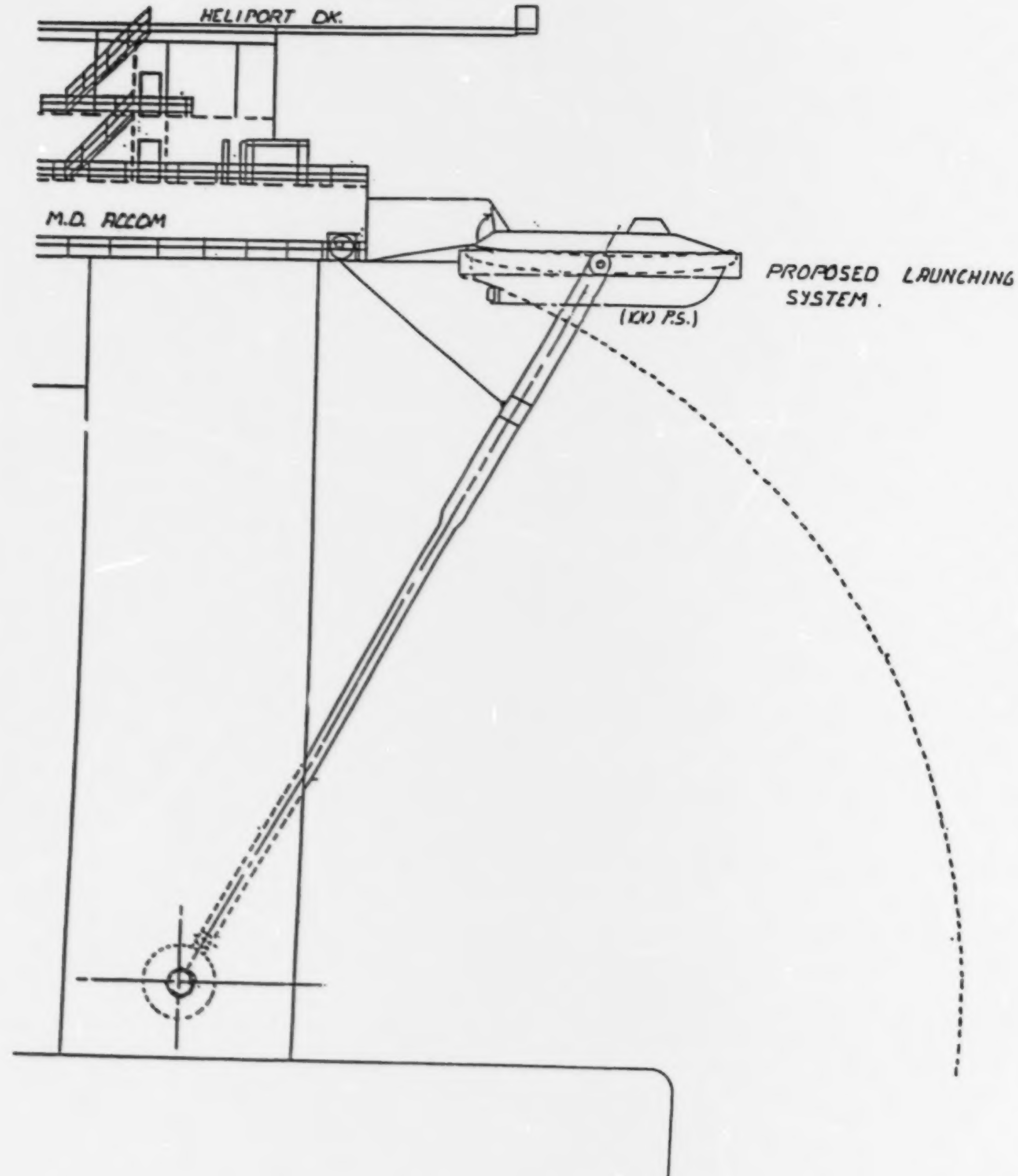

HELIPORT DK.
M.D. ACCOM
PROPOSED LAUNCHING SYSTEM.
(XY) P.S.)

FIGURE 2.

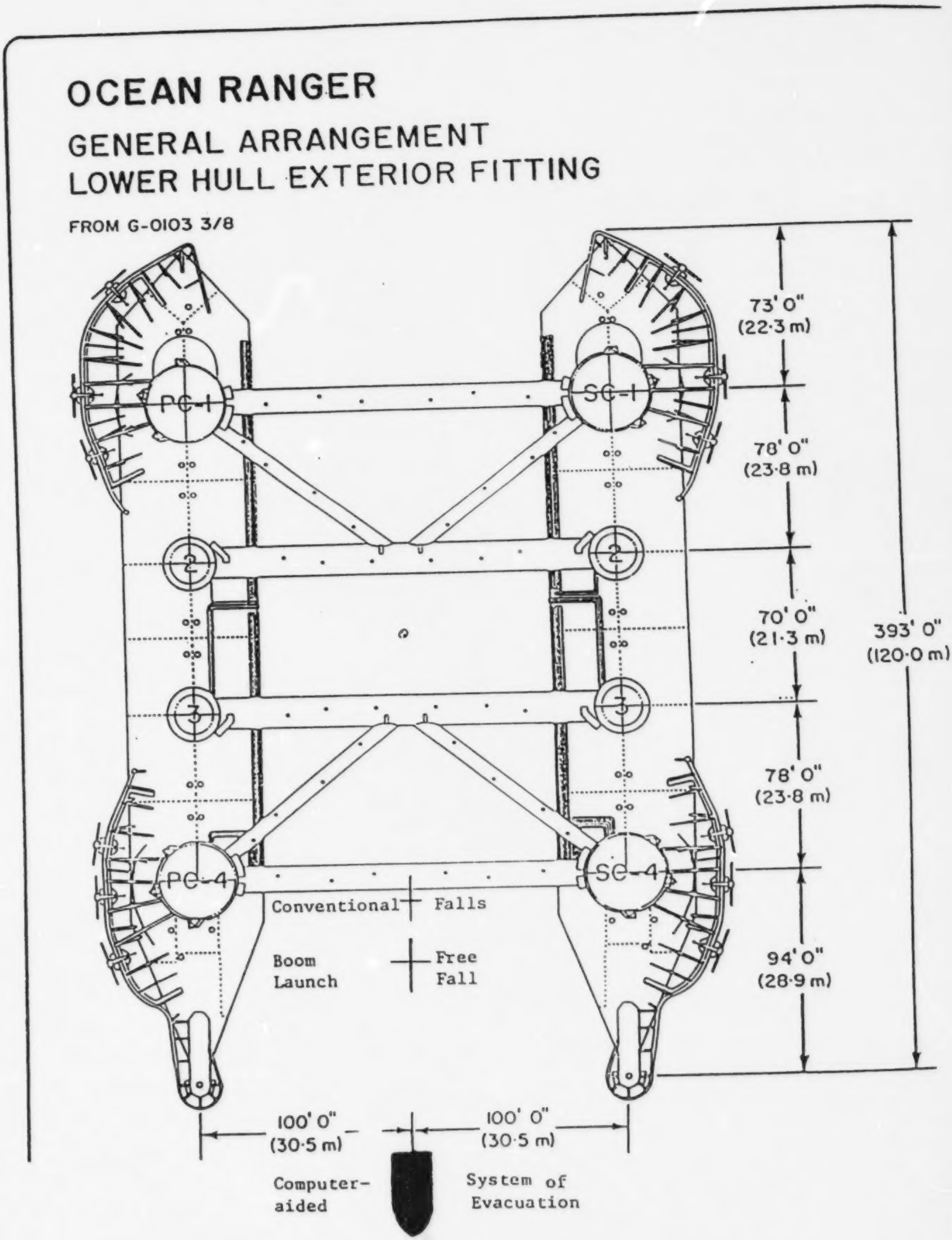
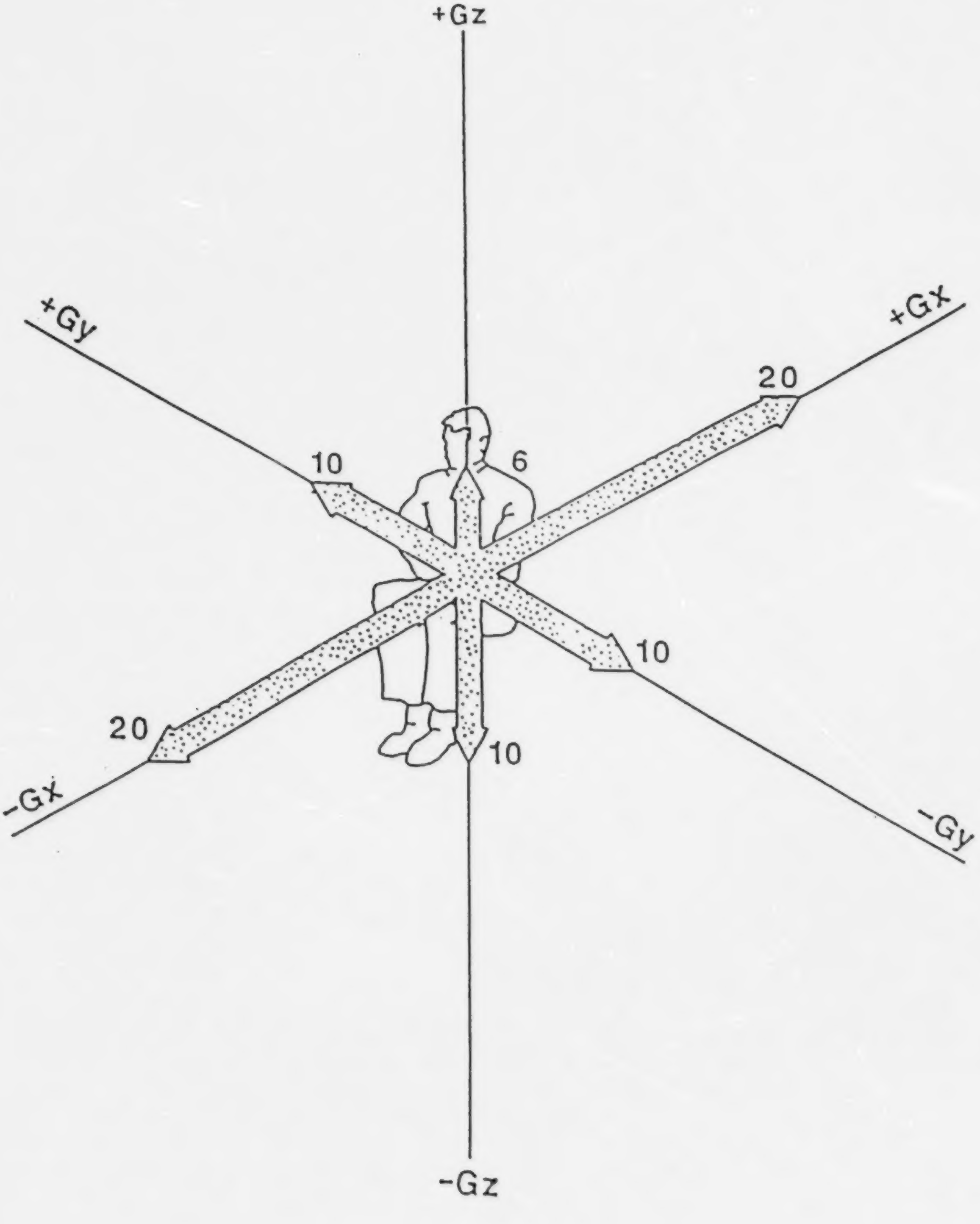

OCEAN RANGER
GENERAL ARRANGEMENT
LOWER HULL EXTERIOR FITTING
FROM G-0103 3/8
PC-1
SC-1
2
2
3
3
PC-4
SC-4
73' 0" (22·3 m)
78' 0" (23·8 m)
70' 0" (21·3 m)
78' 0" (23·8 m)
94' 0" (28·9 m)
393' 0" (120·0 m)
100' 0" (30·5 m)
100' 0" (30·5 m)
Conventional Falls
Boom Launch
Free Fall
Computer-aided System of Evacuation

FIGURE 3.


+Gz
+Gy
+Gx
20
10
6
10
20
10
-Gx
-Gy
-Gz

PHYSIOLOGICAL LIMITS TO ACCELERATIONS

FIGURE 4.

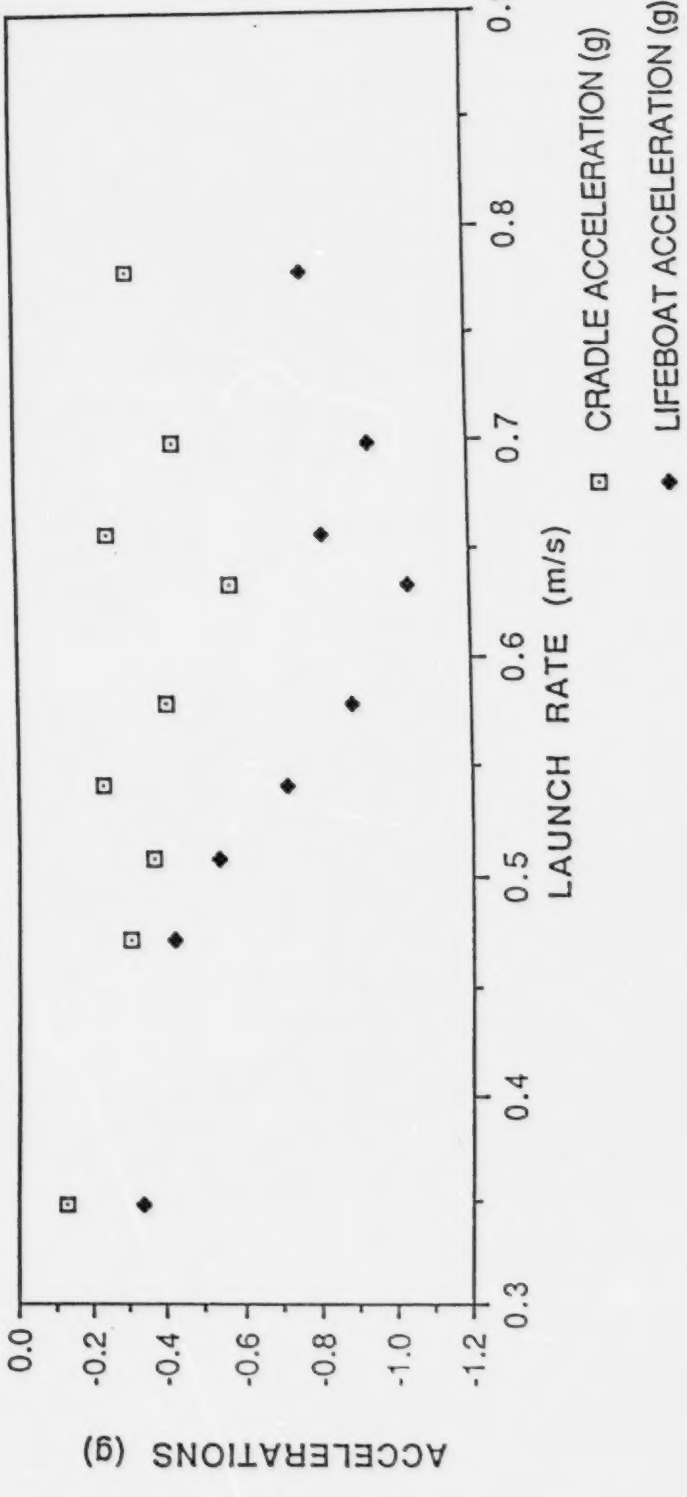


FIG. 14 COMPARISON OF VERTICAL ACCELERATIONS IN CALM WATER DEPLOYMENT

TABLE 1.

SPEAKER : **WALTER BOBBY**

COMPANY : **CANADA-NEWFOUNDLAND OFFSHORE PETROLEUM BOARD**

LOCATION: **ST. JOHN'S, NEWFOUNDLAND**

TOPIC : **CERTIFICATION OF OFFSHORE INSTALLATIONS:REGULATORY REQUIREMENTS**

BIOGRAPHY: Walter Bobby is Senior Structures Engineer with the Canada-Newfoundland Offshore Petroleum Board. He has a Ph.D in Engineering Mechanics from Indian Institute of Technology, Madras and is a member of APEN. He was involved with offshore structures research at Memorial University of Newfoundland and since joining the Government in 1981 has participated in the development and administration of regulations for offshore facilities.

ABSTRACT

CERTIFICATION OF OFFSHORE INSTALLATIONS: REGULATORY REQUIREMENTS

As part of its consideration of applications for approval of proposed activities in the Newfoundland offshore area, the Canada-Newfoundland Offshore Petroleum Board (Board) reviews the equipment, facilities, personnel training and procedures to be used to ensure that personnel safety and environmental protection have been taken into account. The government is now proposing to promulgate regulations concerning the certification of offshore installations requiring a comprehensive third party review and the issuance of a Certificate of fitness by Certifying Authorities recognized by governments. The proposed certification scheme is compared with legislation in other countries. Elements that differ with the other jurisdictions are identified.

The paper outlines the requirements for obtaining and duration of a Certificate of Fitness which certifies that the installation complies with the regulations and is fit for the intended purpose. The Certifying Authority accomplishes this by conducting and independent review and associated surveys of the design, construction, installation and maintenance of the offshore installation. To satisfactory condition, the Certifying Authority will also review the proposed operations manual and the monitoring and inspection programs and will periodically survey the installation, to ensure that the certification remains valid.

In order to perform its duties, the Certifying Authority requires documentation on the design and has to review fabrication and equipment manufacture. The effect of the proposed certification scheme on operators, contractors, engineering consultants,, suppliers and fabricators is discussed.

CERTIFICATION OF OFFSHORE INSTALLATIONS: REGULATORY REQUIREMENTS

Introduction

The Canada-Newfoundland Offshore Petroleum Board (Board) was established by an Act of Parliament, The Canada-Newfoundland Atlantic Accord Implementation Act and by a parallel Act in the Newfoundland House of Assembly, the Canada-Newfoundland Atlantic Accord Implementation (Newfoundland) Act. The Board is responsible for administering regulations governing the exploration for and production of hydrocarbons in the Newfoundland offshore area. One such regulation is the Certificate of Fitness regulations.

The mandate of the government is to protect public interest, which in the case of offshore petroleum exploitation, involves the safety of the personnel, the safety of the environment and the conservation of resources. To achieve these goals, the structure and equipment used have to be sound, appropriate procedures have to be followed and competent personnel employed. Some of these goals are achieved when the design, construction and installation are performed according to requirements that are suitable for the type of installation and appropriate for the location. To ensure this, an independent review of the design, construction and installation should take place.

Offshore installations are large and complex. The review of an offshore installation requires different specialised expertise. It would be impractical to establish such a group within the government to conduct the review. An organization with a wide range of expertise and experienced in conducting assessments is required. One of the recommendations of the Royal Commission on the Ocean Ranger Marine Disaster is that an assessment of the physical integrity and stability of the rig be carried out preferably by a classification society. The Harrison Task Force that was set up subsequent to the Royal Commission to assist the Minister of Energy, Mines and Resources in developing a proposal for a comprehensive oil and gas act also recommended a Certificate of Fitness approach.

The Certificate of Fitness regulations have been drafted to authorize recognized certifying authorities to issue Certificates of Fitness in respect of an offshore installation. The draft Certificate of Fitness regulations have been reviewed by the industry and is awaiting legal review prior to promulgation expected by next year. Until such time the requirements in the draft regulations will apply by reference in work authorizations.

Certifying Authorities

Four certifying authorities have been recognized to issue Certificates of Fitness. They are:

American Bureau of Shipping,
Bureau Veritas,
Det norske Veritas (Canada) Ltd., and
Lloyd's Register of Shipping.

They were selected by a certification review panel consisting of senior officials from the federal and the provincial energy departments and the Board, based on information supplied by applicants and an interview process.

Types of Installations

Four types of installations will require a Certificate of Fitness: production installations, drilling installations, accommodation installations and diving installations. Only one certificate is issued for an installation and the review of an installation includes all associated facilities. For e.g., the review of a production installation includes the structure and the production system, and as applicable, the drilling equipment, the accommodations and the diving system.

A production installation includes the fixed or mobile platform, the associated equipment for the production of oil or gas including the christmas tree and the subsurface safety value, subsea production system including flowlines, drilling equipment, export lines to the loading platforms, the loading platforms and may include a diving system.

A drilling installation includes the drilling equipment, the marine riser, blow out preventer, associated fixed or mobile platform and may include a diving system.

An accommodation platform is primarily used to provide accommodation for people working on the production or drilling installations and may include a diving system. An accommodation installation may be used to support offshore construction and commissioning.

A diving installation is a vessel with a diving system used to provide diving support for offshore activities.

Issue of Certificate of Fitness

The regulations require four conditions to be met before the certifying authority issues a Certificate of Fitness for an installation:

- the installation is designed, constructed and installed in accordance with the applicable regulations;
- the installation is fit for the purpose for which it is to be used and can be operated safely without polluting the environment;
- the inspection, maintenance and weight control program is reviewed and approved, and
- the scope of work approved by the Chief Conservation Officer is carried out.

Compliance with Regulations

The certifying authority may issue a Certificate of Fitness for an installation if he is satisfied that the installation is designed, constructed, transported and installed or established in accordance with the relevant regulations. The applicable regulations are:

Production and Conservation Regulations,
Installations Regulations,
Drilling Regulations,
Occupational Safety and Health Regulations, and
Diving Regulations.

A brief description of the regulations is provided. The description is limited to the extent that it has a bearing on certification.

The Production and Conservation Regulations provides the regulatory frame work for the production of oil and gas. Prior to production, the operator must obtain a production licence and Production Operations Authorization from the Board. The application for a Production Operations Authorization should include a valid Certificate of Fitness for the production installation. The regulations also specify safety related requirements for equipment, well head and christmas trees and measurement and testing equipment such as meters and valves.

The Installations Regulations provide the requirements for the design, construction and installation of all four types of installations. The requirements are such that a target reliability of greater than $1-10^{-5}$ per annum is achieved in the design.

The regulations also require that the design, construction and installation of the installation should be in accordance with CSA Z299 Quality Program Standards. Specific requirements are introduced by referencing CSA, API and other standards. The regulations include construction, installations, abandonment requirements and the requirements for the contents of an operations manual. Specific requirements for the following subsystems are included:

- helideck,
- electrical/mechanical equipment,
- cranes,
- emergency shutdown,
- safety systems,
- lifesaving appliances,
- fire protection,
- ballast and bilge,
- mooring and dynamic positioning, and
- subsea production systems.

The regulations require the approval of the Chief Conservation Officer and certifying authority for repairs and alterations.

The drilling regulations specify the requirements for obtaining Drilling Program Authorization. The drilling installation is approved for use as part of the Drilling Program Authorization. The regulations include general requirements for the design of the drilling installation. The drilling equipment is essentially required to be designed to API standards.

The Diving Regulations give the requirements for obtaining diving program authorization and the certification of diving personnel. The regulations provide general requirements for the design and testing of diving equipment including the communication system, pressure vessels and oxygen supply system. The regulations also specify requirements for the use of a dynamically positioned vessel.

The Occupational Safety and Health Regulations provide requirements related to the occupational safety and health of employees in offshore operations. The regulations provide requirements related to:

general safety,
electrical safety,
sanitation,
hazardous materials,
elevating devices,
pressure systems,
levels of lighting and sound,
machinery and materials handling, and
confined spaces.

The regulations are under review by the Justice Department and are expected to be promulgated this year.

Fit for Purpose

The certifying authority has to be satisfied that the installation is fit for the purpose for which it is to be used and can be operated safely without polluting the environment.

Inspection, Maintenance and Weight Control Program

The certifying authority will review and approve the inspection, maintenance and weight control program. The certifying authority must be satisfied that the installation will continue to comply with the regulations and be fit for purpose for the period of validity endorsed on the Certificate of Fitness. The certifying authority when reviewing the inspection, maintenance and weight control program will ensure that the Certificate of Fitness will continue to be valid if the program is followed.

Scope of Work

The owner/operator contracts the certifying authority to issue a Certificate of Fitness. The scope of work associated with the contract must be approved by the Chief Conservation Officer. The certifying authority is bound to perform the requirements described in the scope of work. Variations to the scope of work during certification would be approved by the Chief Conservation Officer.

Variance with Other Jurisdictions

Certification is not new to the offshore industry. All installations in the UK offshore area have a Certificate of Fitness. Some form of certification is also found in other jurisdictions. However, there are differences in the proposed Canadian certification scheme.

The certifying authority will review the total installation, including flowlines, lifesaving appliances and firefighting equipment. In the UK the review of flowlines is done by the Department of Energy and the lifesaving appliances and firefighting equipment are reviewed by the Department of Transport.

Quality assurance programs have been used by some of the operators. The regulations require the design, construction and installation to be in accordance with the CSA Z299 Quality Program Standards. The latest edition of the UK Guidance Notes states that the use of quality systems is encouraged.

The UK Department of Energy has published regional maps for environmental design criteria. Similar maps are not included as guidance to the Canadian regulations. The Department of Environment, however, has a large archive of environmental data that the operator can access to develop site specific environmental design criteria. The certifying authority will review the design criteria and the methods used to derive them. Ice and icebergs are unique to the Canadian offshore.

Safety analysis is one of the requirements in the Canadian regulations. The safety analysis of the concept should be submitted with the Development Plan and a risk analysis of the installation should be included in the Safety Plan submitted with the application for Production Operations Authorization. These analyses may be reviewed by the certifying authority. The UK Department of Energy has published a discussion paper on formal safety assessment outlining requirements for such analyses.

Other Considerations

In addition to the work done for the issue of a Certificate of Fitness, the regulations specify other considerations related to certification. These are:

- Conflict of Interest,
- Duration of Certificate of Fitness,
- Change of Certifying Authority, and
- Cancellation of Certificate of Fitness.

Conflict of Interest

The draft regulations prohibit the certifying authority of an installation to have been previously involved with the installation other than as a verification body. If the certifying authority is involved with generating part of a preliminary design or detailed design, then that organization must not act as a certifying authority for that installation.

Duration of Certificate of Fitness

The maximum duration of validity of the Certificate of Fitness is five years. On the basis of a comprehensive survey prior to the expiry of the certificate, a new Certificate of Fitness may be issued by the certifying authority. If the certifying authority is not satisfied that the installation will remain fit for a five year period, the certifying authority may issue the certificate for a shorter period. The certifying authority endorses on the certificate the area of validity of the certificate.

Change of Certifying Authority

The certifying authority that issued the initial Certificate of Fitness for the installation usually remains the certifying authority for the full life of the installation. However, if circumstances arise that necessitate a change in the certifying authority, the old certifying authority is obligated to transfer a copy of all records and drawings related to the certification of that installation in a timely manner and provide a comprehensive status report of certification activities at the time of the transfer, to the new certifying authority.

Cancellation of Certificate of Fitness

The Chief Conservation Officer or the certifying authority may cancel the certificate, if it is determined that the applicant had submitted incorrect information or the installation has changed in character to the extent that it does not comply with the regulations or the approved inspection, maintenance or weight control program is not followed. The Chief Conservation Officer may cancel the certificate if he determines that the certifying authority has failed to carry out the requirements as described in the approved scope of work. Thirty days notice should be given to provide an opportunity to the owner/operator to provide additional information that could reverse the proposed action.

A Certification Project

Figure 1 shows the proposed Hibernia production system components. The certifying authority's review includes the GBS production platform, the production manifold, gathering line, flowlines, christmas trees at subsea well locations, crude transfer lines and offshore loading systems. the tanker is not part of the installation. Figure 2 shows the development schedule. It is advantageous to have the certifying authority on board early in the project. The certifying authority is likely to be appointed shortly after the start of the project when the topside and GBS contracts are awarded. The flow chart for certification is shown in Figure 3. the operator selects one of the recognized certifying authorities. The Board approves the scope of work and certification reviews commence. The certifying authority submits monthly reports on the progress of certification to the Board. The operator provides information from and access to the designer, material supplier, construction and fabrication contractors, equipment manufacturer, marine contractor and maintenance contractor. When the certifying authority is satisfied, he issues a Certificate of Fitness and endorses on the certificate the area of validity, duration of the certificate and any limitation considered necessary. During the duration of the certificate, the certifying authority conducts regular surveys to ensure compliance with the approved inspection, maintenance and weight control program. Prior to the expiry of the certificate, the certifying authority conducts a comprehensive survey of the installation and may issue a new certificate.

Certifying Authority

The role of the certifying authority is to review data, analyses and drawings provided by the operator and conducts independent analysis, as necessary, to be satisfied that the design is sound. He reviews the construction methodology and the quality assurance program. The certifying authority may survey the material supplier, the manufacturer, and the construction, fabrication and installation as required. After installation, he surveys the installation periodically in accordance with the approved the inspection, maintenance and weight control program.

Owner/Operator

The primary responsibility for safety rests with the owner/operator. The Certificate of Fitness does not relieve the owner/operator of that responsibility. Further, the owner/operator is responsible for the following:

- Apply for and maintain a valid Certificate of Fitness;
- Provide all information required by the Certifying Authority to perform an assessment;
- Assist the Certifying Authority in carrying out the surveys;
- Obtain approval from the Certifying Authority and the regulator for alteration and repairs.

The following types of information should be supplied to the certifying authority:

- Design premise;
- Environmental reports;
- Geotechnical reports;
- Model tests;
- Analyses reports;
- Design Documentation;
- Drawings;
- Inspection, maintenance and weight control program;
- Operations Manual; and
- Quality Assurance program.

Designer

The design documentation should include analyses of the foundation and the structure. The design of mechanical, electrical and safety systems should be submitted for review. The certifying authority also reviews the design and construction drawings.

When a certifying authority is brought on board at an early stage, design packages may be submitted for review as they are produced, and any potential problem can be quickly identified. All communications to the certifying authority are likely to be through the owner/operator, however, an individual or individuals may be identified to communicate with the certifying authorities. As with any project, regular meetings may take place to review the certification program.

Source Materials

Materials used in the primary structure may be subjected to inspection by the certifying authority. The certifying authority may witness physical and non-destructive testing of material in accordance with the relevant specifications.

Fabricator/Construction Contractor

A major portion of the certification review of fabrication and construction takes place at the fabrication and construction site. The certifying authority may be resident on site.

The fabricator and construction contractor should be aware of the items that the certifying authority will review. This would help them to obtain consent of the certifying authority. Some elements of review by the certifying authority are:

- material identification,
- welding procedures and qualifications,
- non-destructive testing,
- fabrication,
- dimensional checks,
- formwork,
- reinforcement,
- prestress ducts and anchorages,
- concrete batching and testing,
- concrete placement,
- stripping shutters and curing,
- prestressing, and
- repair.

Manufacturer

The certifying authority will select and notify the owner/operator of the equipment to be reviewed. He may review the design and conduct inspections at the manufacturing plant. The items normally selected are:

- pressure vessels
- pumps and compressors
- lifting devices
- combustion engines and turbines
- hydrocarbon piping etc.

The certifying authority may review the inspection and test reports of the equipment that it does not survey during manufacture. The certifying authority reviews the installation of the equipment on the platform and the testing during commissioning.

Maintenance Contractor

The certifying authority reviews the maintenance logs and the surveys and tasks done by companies contracted by the owner/operator for compliance with the approved inspection, maintenance and weight control program. It is important that these organizations are aware of the requirements of the certifying authority for their test reports.

Marine Contractor

The structure is normally built onshore or near shore. It has to be moved to the offshore site and installed. A marine warranty consultant will normally oversee the marine operation. The certifying authority reviews the analyses related to marine operations and surveys seafastening to ensure that the integrity of the installation will not be adversely affected during the tow to site and installation on location.

Closure

Certification provides a third-party review that helps the effort to identify undesirable trends and provides confirmation for solutions to problem areas with respect to safety and pollution control.

It should be recognized that certification does not provide a guarantee of the integrity of the installation but it provides an assurance that there is a high degree of probability that proper procedures, technology and materials have been used and that no recognizable problems have been overlooked.

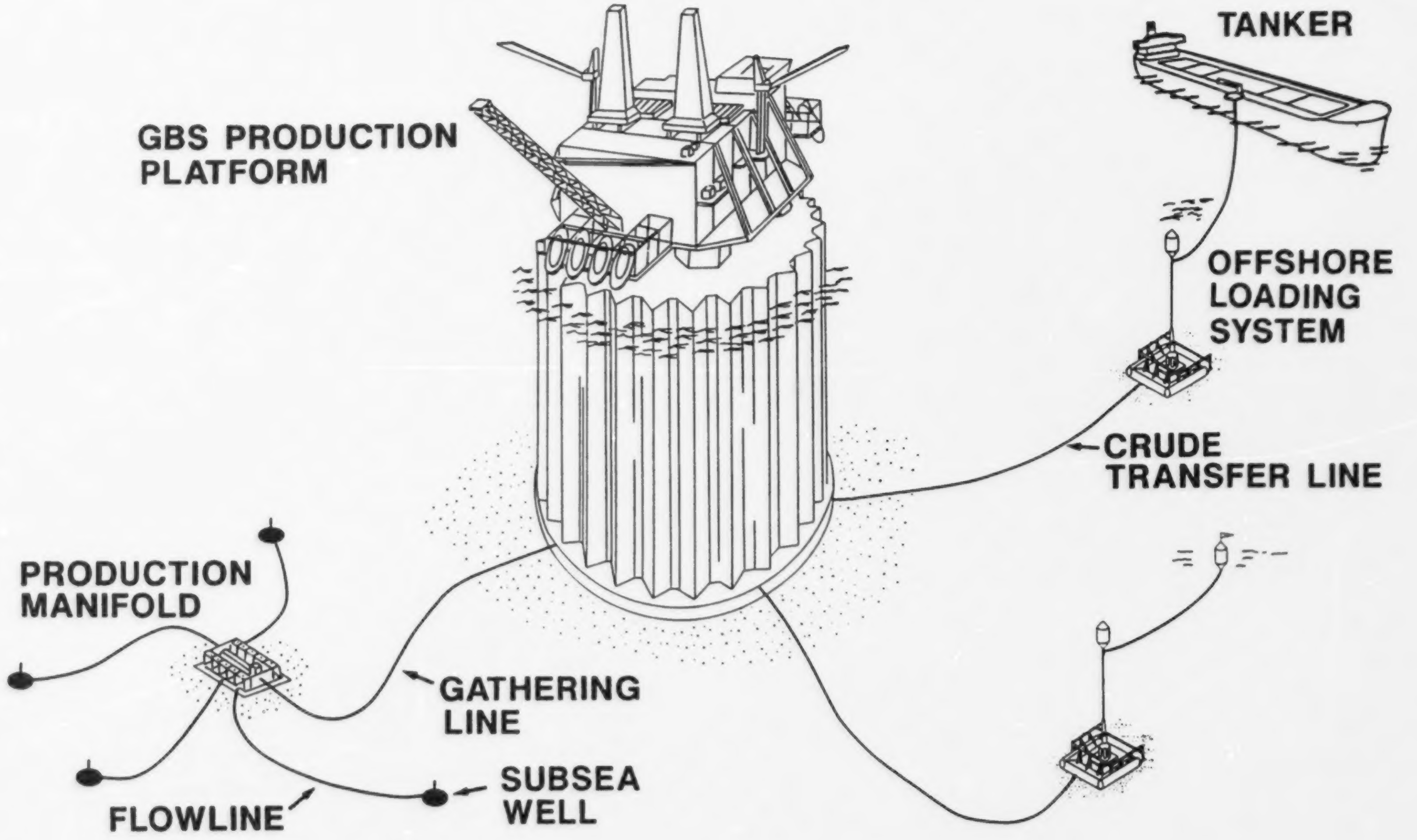

TANKER
GBS PRODUCTION PLATFORM
OFFSHORE LOADING SYSTEM
CRUDE TRANSFER LINE
PRODUCTION MANIFOLD
GATHERING LINE
SUBSEA WELL
FLOWLINE

Figure 1. Production System Components (Mobil Hibernia Development Plan Update, 1990)

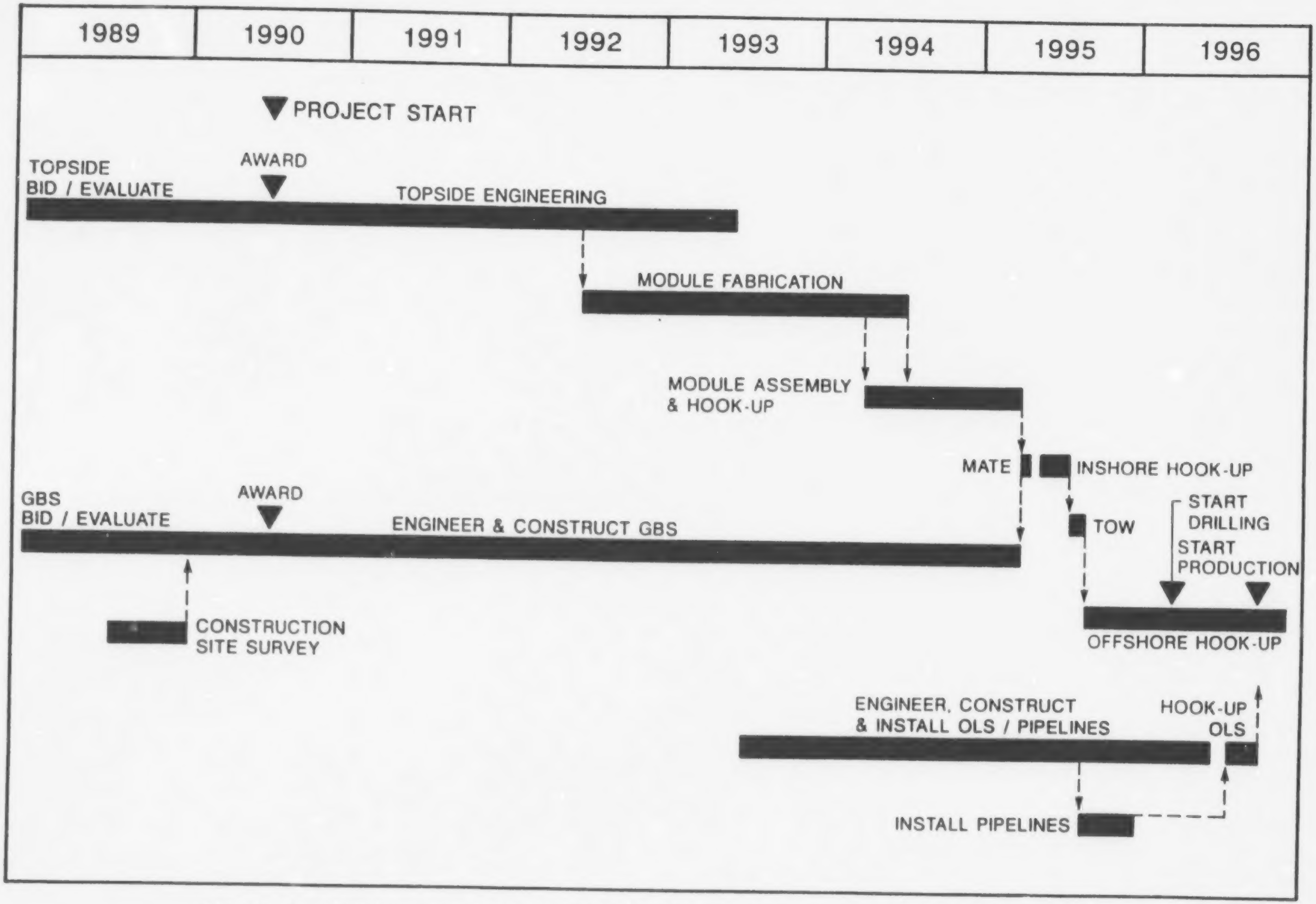


Figure 2. Development Schedule (Mobil Hibernia Development Plan Update, 1990)

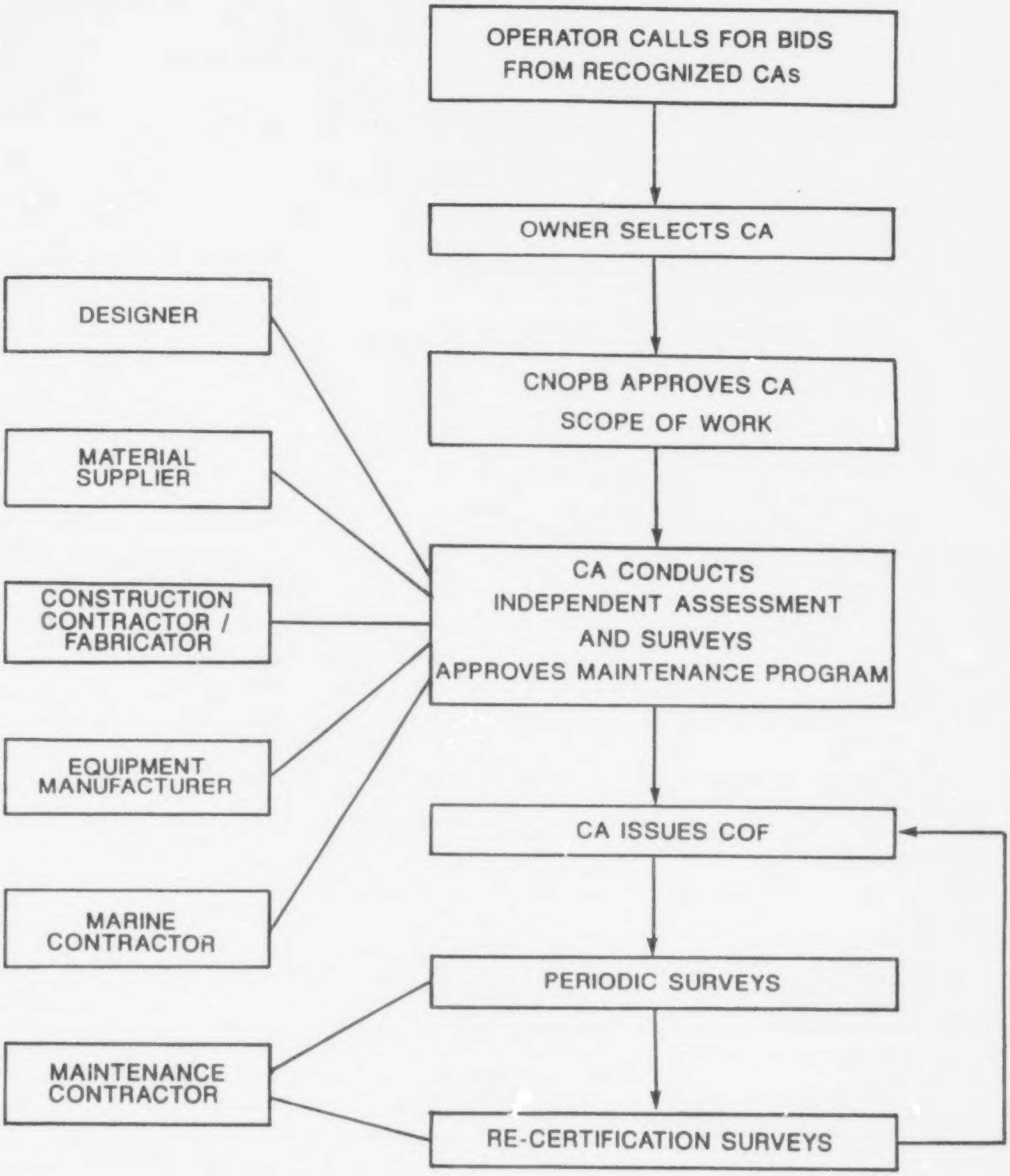

OPERATOR CALLS FOR BIDS FROM RECOGNIZED CAs
OWNER SELECTS CA
CNOPB APPROVES CA SCOPE OF WORK
CA CONDUCTS INDEPENDENT ASSESSMENT AND SURVEYS APPROVES MAINTENANCE PROGRAM
CA ISSUES COF
PERIODIC SURVEYS
RE-CERTIFICATION SURVEYS
DESIGNER
MATERIAL SUPPLIER
CONSTRUCTION CONTRACTOR / FABRICATOR
EQUIPMENT MANUFACTURER
MARINE CONTRACTOR
MAINTENANCE CONTRACTOR

Figure 3. Flow Chart for Certification

SPEAKER : **MICHAEL JAMES STRONG**

COMPANY : **NEWOCEAN CONTRACTORS LIMITED**

LOCATION: ST. JOHN'S, NEWFOUNDLAND

TOPIC : **EFFECT OF OIL PRICES ON THE DESIGN OF OFFSHORE PROJECTS IN THE 1990s**

BIOGRAPHY: Born in 1946, Mr. Strong spent the first sixteen years of his life living mostly abroad in places such as Germany, Kenya and Cyprus as his father was a career officer in the Royal Air Force Regiment.

He went to sea at 17 as a Cadet, attaining his Masters Certificate in 1972, and his first command at the age of 27. Seeing no future in the British Merchant Navy, he joined the oil industry in 1977, initially as an Assistant Marine Superintendent. His career has grown with the development of the North Sea over the past 13 years and he has gradually moved from the marine related offshore operations to the offshore construction field. He operates as an independent consultant, and his clients have included Chevron, Shell, BP, Conoco and BNOC/Britoil prior to the BP takeover. His last position prior to joining Newocean was as Offshore Construction Representative and Field Coordinator on Conoco's Southern Basin Gas Development, the largest single offshore construction project in the North Sea in the last five years.

ABSTRACT

EFFECT OF OIL PRICES ON THE DESIGN OF OFFSHORE PROJECTS IN THE 1990s.

Offshore field development consists of 6 phases:

1) Seismic Survey
2) Exploration Drilling
3) Delineation Drilling/Reservoir Engineering
4) Platform Design
5) Platform Construction
6) Production Operations

Since the oil price crash of 1986, all of the above 6 categories have been radically redeveloped to reflect the lower margins in todays crude oil markets. This has resulted in a leaner industry, and technological developments which may otherwise have taken a decade or more to bring to fruition, have in fact been accomplished in a matter of months. (Below is a brief abstract of topics).

1) Seismic Survey - Computer enhanced seismic data interpretation - The use of variable pulse speed in differing strata density- 3-D seismic models - Ability to pinpoint pay zones, domes, caps, reverse thrust formations - Ability to more accurately place exploration activity.

2) Exploration Drilling - More rapid drilling techniques - Top drive assemblies - Oil based muds - High horsepower anchor handlers. MWD techniques.

3) Reservoir Engineering - Advanced logging techniques - Ability to drill horizontal or strata following completions - Step out wells - Restrictions on reservoir engineers by one central platform concept - BP's forties 2 platform instead of 5- Enhanced recovery techniques - Water & gas injection- Interface between reservoir engineering & delineation drilling.

4) Field Design - Parameters for maximum profitability from reservoir engineering/ delineation drilling results - Reduction of topside and consequently jacket weights - Reduction of manpower - Subsea completion techniques - Tie back wells- Unmanned satellites.

5) Construction - New generation of SSCV's - Super Module/integrated deck concepts - Pre-commissioning ashore-Reduction of offshore hook-up + manpower - New pipelaying technology - CDTMS - Workover satellite wells/structures-Subsea completions UMC manifold concepts.

6) Operations - Reduced operational staff - telemetry to unmanned satellites - Data Transmission to beach - Workover and well enhancement thru satellites both sub and above surface-reservoir fraccing and acidification - Subsea separators-Removal of topsides requirements - Gas re-injection/processing/conversion to syncrude.

Conclusion - Field development by combining all above procedures reduction in development drilling, construction and operational costs. Field development design relevant to abandonment on expiry - Environmental requirements,etc.

Good morning Ladies and Gentlemen. The title of my paper this morning is "The Effect of Oil Prices on the Design of Offshore Projects in the 1990's." I shall attempt in the next 45 minutes to present an overview of the technology which is currently being developed and implemented by some of industries most innovative thinking, in one of the harshest industrial environments, the offshore oil fields.

And yet to be able to do this against the background of uncertain and fluctuating oil prices, and still maintain profitability.

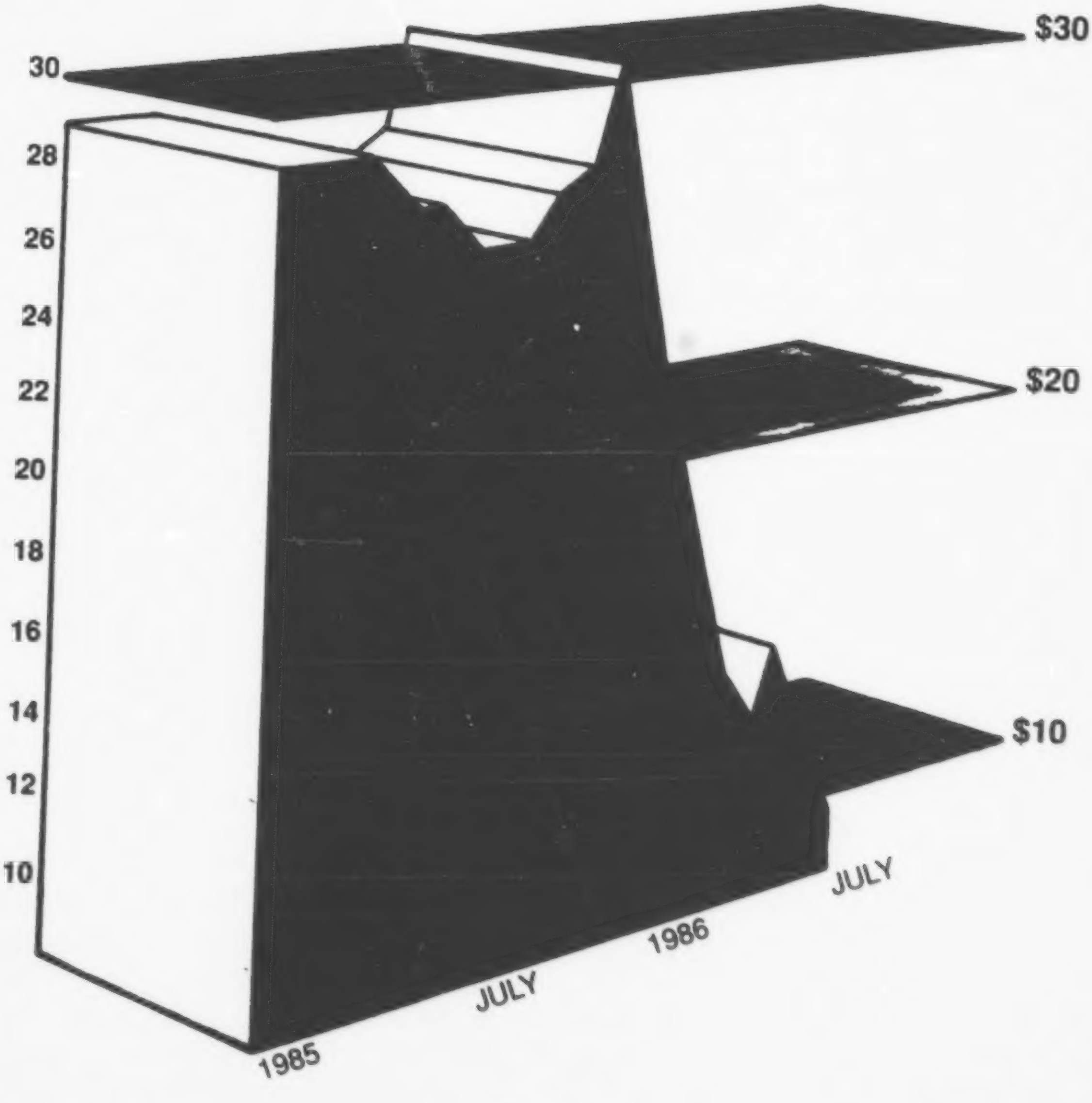
On July 23rd., 1986, a cargo of brent crude was lifted from Sullom Voe at approximately $8 and 70 cents per barrel. This represented the climax of a downward price struggle that was based on a number of international factors. (Figure 1)

The domination of the OPEC producers allowed the massive crude oil price increases of the early and late seventies. Western economies were severely shaken by the almost overnight quadrupling of the cost of their fuel supplies in 1974.

Non OPEC producers, blessed with massively more valuable raw product, were encouraged or even obliged to invest more and more in exploration and production from increasingly unlikely and expensive environments.

By the late seventies large North Sea fields were being brought on stream in ever deeper and harsher locations. The heady prices of $32 - $34 dollars per barrel allowed larger and larger platforms to be designed and built with almost no budgetary constraints, and still provide a handsome return on investment.

In the meantime, other offshore provinces such as West Africa, Mexico, Indonesia and Brazil were no less active. The



BRENT CRUDE

FIGURE 1

combined effect of this activity produced the inevitable result. Basic market forces of supply and demand kicked in and in 1982 OPEC, with its grip on the market severely weakened, set production quotas to prop up the price. Non-OPEC production continued to grow, causing a significant weakening of the price. The $35-40 barrel now became fiction and the market hovered between 28-30 dollars between 1983 and 1985 with an ever present downward pressure.

This downward pressure was primarily caused by consistent quota cheating by many of the minor OPEC members. Numerous attempts by Saudi Arabia, as Swing Producer, to whip its fellow members into line had failed, and in January 1986 it carried out its long held threat and opened up the valves. In the following two months the price of crude halved from 28 to 14 dollars, steadied, then fell to its July low of just under 9 dollars a barrel.

There was a second, and to us in the industry, more sinister reason for Saudi Arabia's action. The kingdom had become increasingly nervous of the technological advances being made in provinces such as the UK and Norwegian sectors of the North Sea, not just because of the production from those areas, but of the export of the technology and its proliferation in areas which had been previously no threat to OPEC.

Irritated by his failure to convince the British Government to agree to setting production limits, and aware of the UK's prominence in the development and export of Deep Water Technology, the Saudi Oil Ministers secondary motive in flooding the market was to halt the North Sea Industry dead in its tracks. He nearly succeeded.

Exploration budgets were slashed, rigs and vessels put off hire at the earliest time their contracts would allow, development projects were axed, contract equipment and personnel were run off, and although no major fields were actually shut in operators used the low price environment to reduce production where essential repairs or replacements needed to be carried out. Non essential inspection, repair and maintenance programmes were deferred indefinitely, and dozens of vendor and service companies went to the wall. Tens of thousands of men lost their jobs, some never to return to the industry.

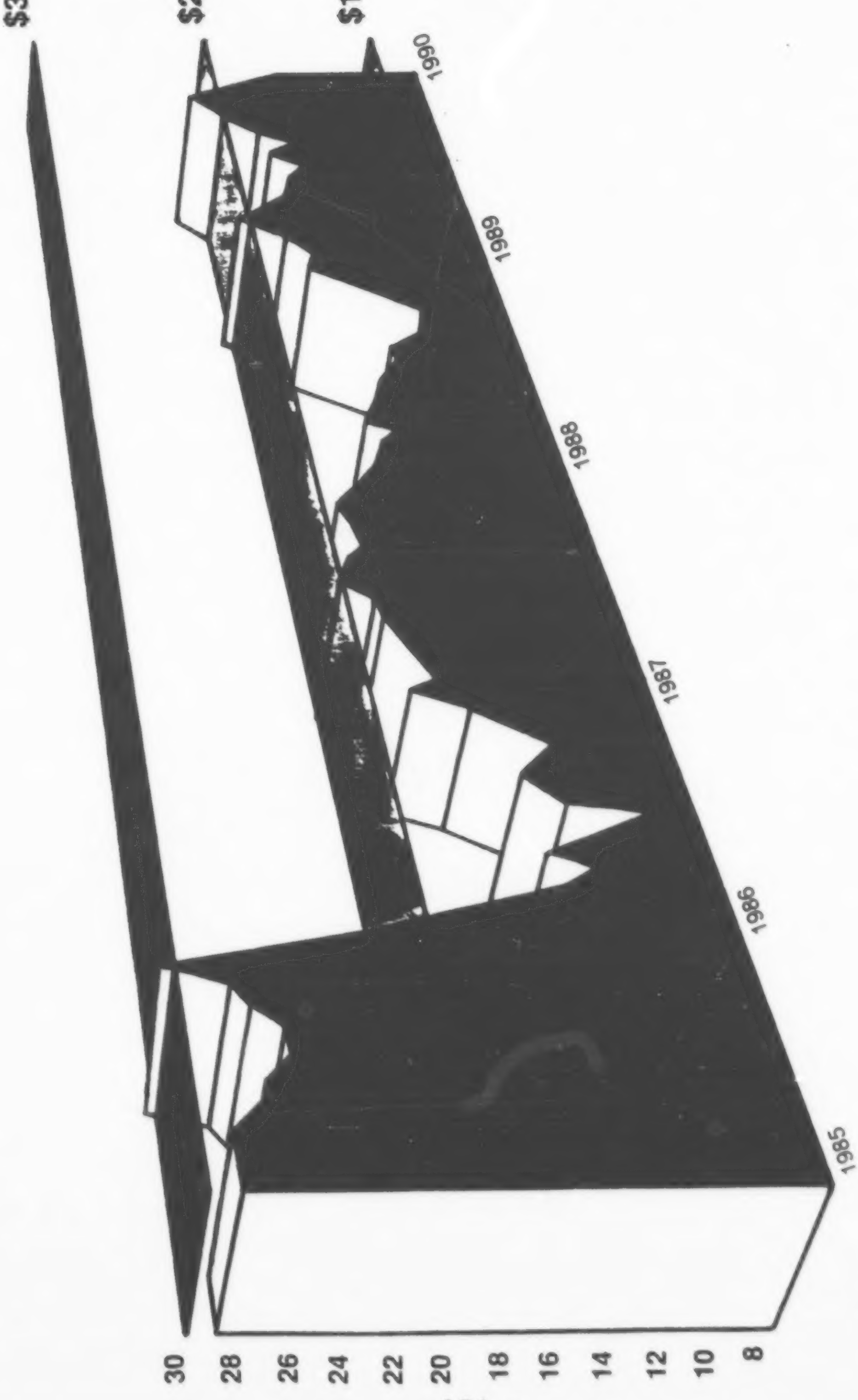
The oil company majors went into a holding pattern, and the minor independents, crippled with cash flow problems and their share prices at rock bottom, became the victims of unwelcome takeovers. The spring and early summer of 1986 was not a happy time for the UK or International Oil Industry.

In this uncertain environment, the Accountant became th most powerful corporate employee, and the red pencil the most important tool in the industry.

Gradually, through a partial return of discipline within OPEC, increasing consumption by the Industrial Nations at giveaway prices, but mainly the realization by Saudi Arabia that it had shot itself in the foot and was unable to sustain its massive expenditure on creating a country out of a desert, prices began to nervously recover. The oil price has fluctuated since 1986 between 12 and 18 dollars, with an occasional peak of around $20. (Figure 2)

As we enter the nineties, the basic problem of crude oil oversupply is still with us, OPEC is still there, and the possibility of seeing a 30 dollar barrel before the year 2000 is remote. It is in this environment that the oil industry has to make its investment decisions. Rather than stop offshore technology, the Saudi Minister forced a tangential rethink on that technology's development.

The lessons of 1986, and the intervening four years have not been wasted. If the price of the raw product is low, and



BRENT CRUDE

FIGURE 2

likely to remain so, then the cost of producing that product must be lowered. If I may quote Dr. John Jennings of Shell, in his speech at the recent offshore conference in Marbella: "The Price Collapse of 1986, though traumatic, was on balance good for the upstream oil and gas industry. It brought us down to earth. There was a lot of fat in the system - Offshore Production Facilities were to an extent overdesigned and could be simplified: organizations had become overmanned and bureaucratic, and could be slimmed down. The downturn also increased competition. In short, costs could be cut significantly without sacrificing reliability."

Dr. Jennings had neatly summarized what the industry must now achieve - improved technology with less people. In the remainder of this paper I shall attempt to outline some of the ways in which this is being achieved and how the economic environment is dictating offshore field design.

Before the designer can put pen to paper, or examine the vast array of technology at his disposal, he must be in possession of as much information about the field as possible. In addition, his awareness of risk management must be high. Risk management is a new tool and industry managers and designers need the maximum guide to the uncertainties they face. Environmental and safety factors must be taken into account, and new methods of analyzing the relative safety of alternative development scenarios at conceptual engineering through to abandonment had been developed.

To obtain this information, a considerable amount of work has to be done in field appraisal. This takes three phases:

1) Geographical and Geophysical Interpretation

   With the advance of the computer industry, and its continuously reducing prices of both hardware and software, seismic information analysis has moved ahead rapidly. In the early days of seismic interpretation, a standard speed of sound through a mean density of rock was all the analysts had to work with. The super computers such as the cray are able to allow for varying signal speeds through different density strata and by rerunning the raw data can enhance and repeatedly fine tune the accuracy of the formations. A classic example of the accuracies now obtainable is in reverse thrust formations where pay zones which were previously missed can now be pinpointed. Computer technology also allows the construction of highly accurate 3D interpretations, again allowing the pinpointing of potential pay zones. This advanced interpretation has avoided many a dry hole, with obvious financial savings to the operator.

2) Exploration Drilling

Armed with state of the art G & G Interpretation, the driller is able to plan his exploration strategy. Once again, the overriding factor is cost; to reach TD as soon as possible, at the cheapest possible cost consistent with safety is the order of the day. (As drilling can comprise 40-60% of an operators exploration and development program this is an area of large potential savings in overall field development.) A number of techniques previously only used in deviated development wells are now being utilized in exploration work. Slim hole drilling, along with oil based muds can reduce the time of a well from 70 days to 30, with a consequent cost reduction of from $11 million to $5 or $6 million. Steerable downhole motors, more advanced M.W.D. tools, PDC bits and top drive assemblies all contribute to a faster and more accurate hole.

3) Reservoir Engineering

Armed with more accurate payzone information obtained by a combination of more accurate G & G Interpretation, more rapid and accurate drilling, and improved well logging techniques the reservoir engineer is now better placed to carry out his estimates on the fields recoverable reserves, their locations, depths and pressures, and hence the ultimate field design. Another significant factor arising from these techniques is that in the mid 1970'S a recoverable reserve of 30% was considered the norm: today that figure is 40% and rising. This, for those non mathematicians present, takes a three hundred million barrel field to 400. Even at 15 dollars a barrel that increases an average sized North Sea field value by 1.5 billion dollars.

Given the extent, complexity, alignment, porosity, permeability and pressures of the various payzones in the field, along with the value of recoverable reserves, the designer is now faced with the realities of extracting those reserves and bringing them to market.

In the heady days of the mid seventies, this was a relatively easy task. An optimum geographical position was selected for the production platform from which all payzones could be reached by the drillers, including any water injection wells that may be required to maximize recovery. The number of wells required would dictate the size and number of drilling facilities required on the platform, including bulk chemical storage facilities, drilling equipment power generation, pipe rack strength and size, mud pits, cementation units and of course accommodation facilities for the drilling crews. (Figures 3&4)

With the known or expected flow rates anticipated from each well, production equipment requirements were also calculated, including water injection and later, gas injection facilities. Multiple stage separation trains, product export pump rooms, machine shops, power generation modules, fire fighting and deluge systems, HVAC modules, messing, sleeping, and recreational modules were all worked out to accommodate the large numbers of hook-up personnel required during H.U.&C as

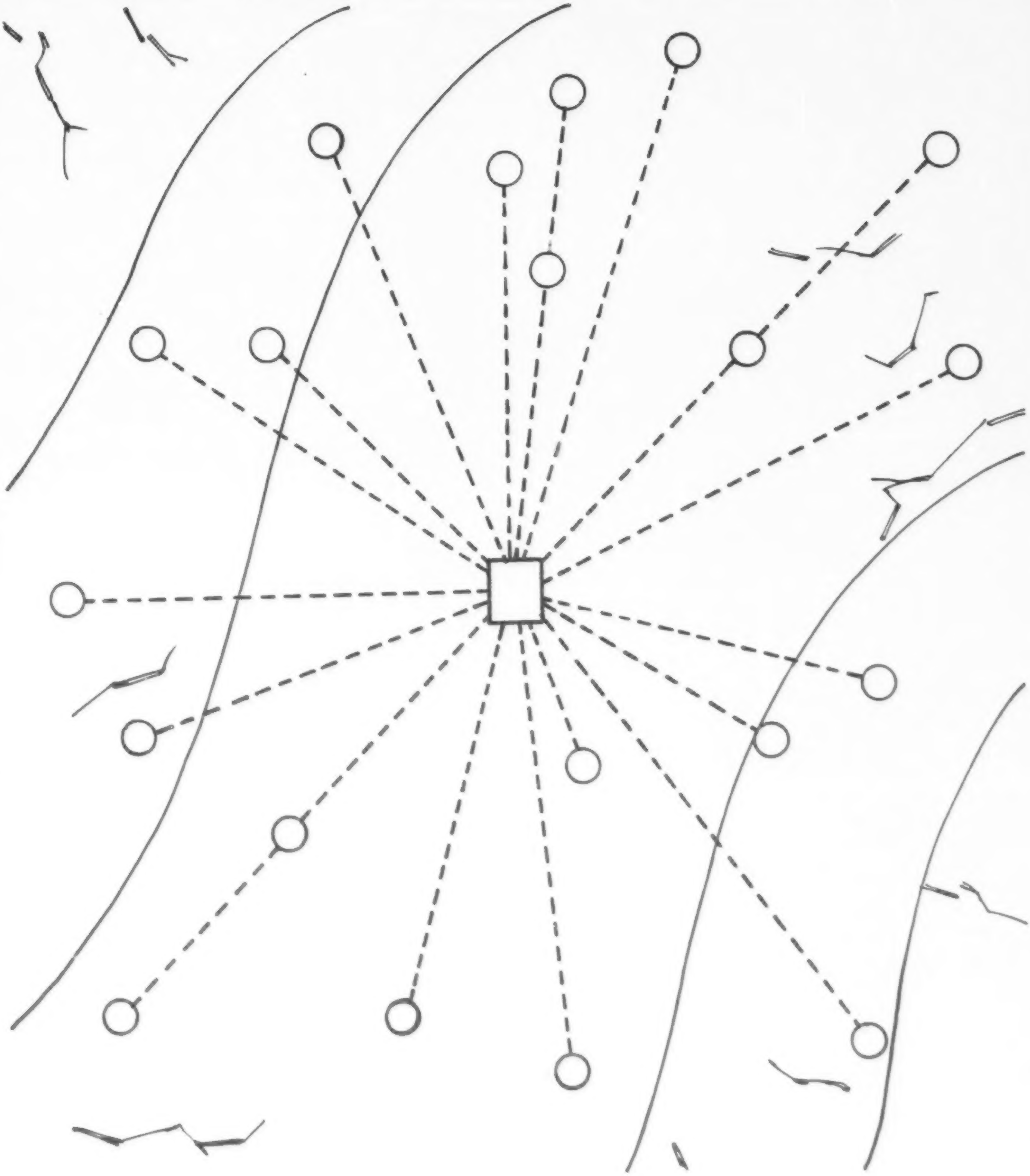


FIGURE 3

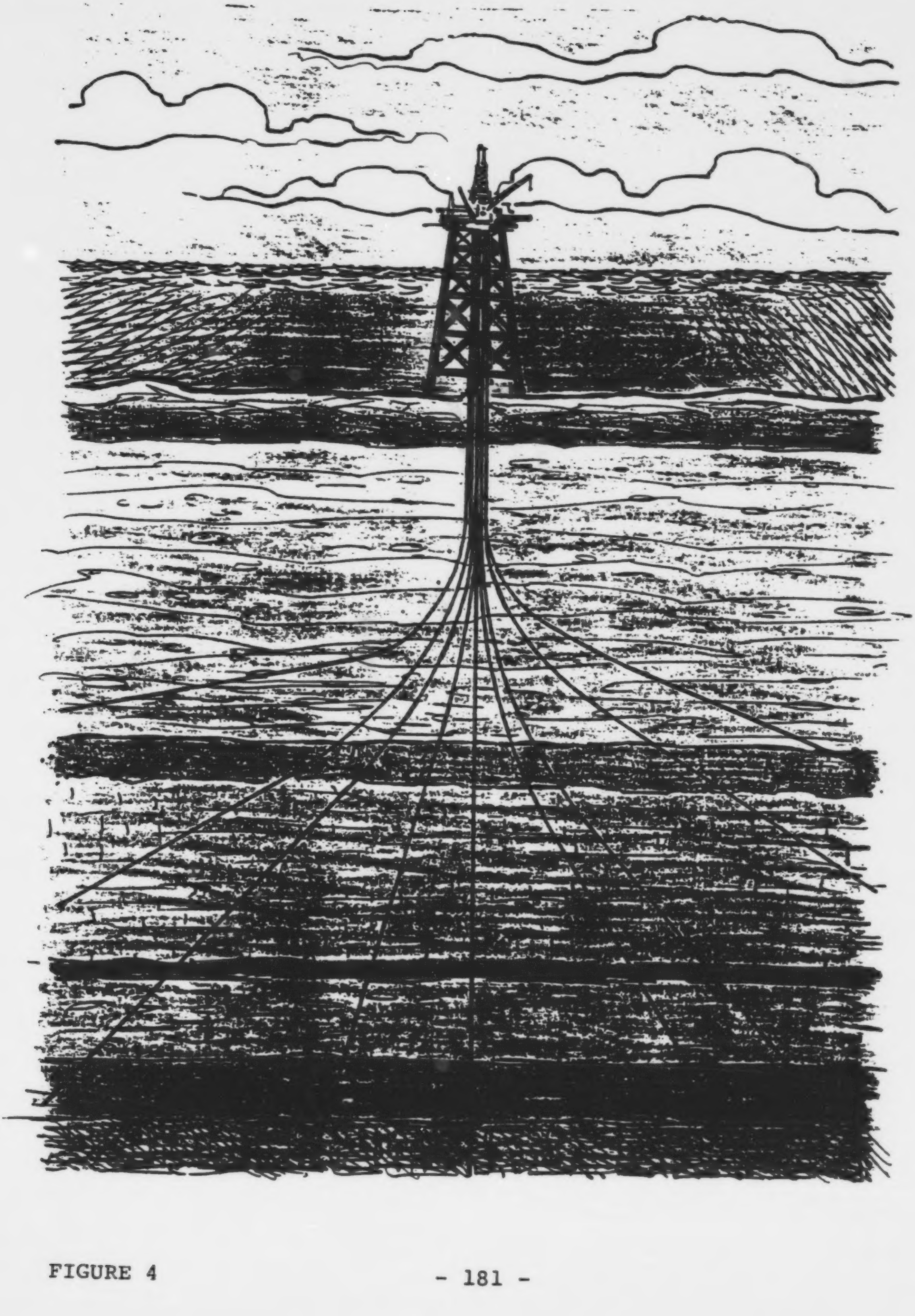


FIGURE 4

well as ongoing production staff. Having obtained the topsides weight requirements, the jacket size and strength could then be designed, additionally affected by the waterdepth. The larger the topsides, the larger the jacket, which itself was increased in strength and weight due to launching stresses and buoyancy or ballasting additions.

Export pipeline or tanker loading buoy arrangements were designed to accommodate the platforms production capabilities.

Cost engineers would then set about the exhausting task of putting a figure on the project cost. Provided that cost left the operator with a healthy return on this investment, from the recoverable reserves at the oil price of the day, the project would proceed, and fields such as Ninian, Brent, Statfjord, Forties and many others are living monuments to the success of those early project calculations.

In the leaner, meaner and tighter economic realities of the 90's Field Design Engineering is not that simple, and the days of these megalithic structures are over.

Now the Design Engineer is faced with his two basic rules of thumb - increase his use of technology, and reduce his manpower, not only in the construction and installation phase, but also in the ongoing operational production life on the field.

Armed with more accurate information on field delineation than his counterpart in the mid 70's his priorities now are:

1) Reduction of topside weight
2) Reduction of jacket weight
3) Streamlining installation/hook up and commissioning
4) Increased use of automation and decentralization of drilling activity

By exploiting his reserves within these guidelines, he is not only able to achieve massive savings in raw material and engineering costs, but reduce his manpower throughout all phases of the field life.

We will now look in more detail at some of the ways that these objectives are being achieved.

REDUCTION OF TOPSIDE WEIGHT

Use of high grade alloy steel for structural/load bearing members

Use of aluminum in accommodation and non hazardous areas

Box girder or truss deck design

Reduction in number of modules

Simplifying process equipment
   a) Hydrocyclones for oil/water separation
   b) Compressed air from gas turbines
   c) Substituting adsorption gas drying for glycol systems

Reduce process contingency equipment

Use of smooth bore pipework allowing higher velocity flowrates thus smaller diameter and lower mass

Reduce storage capacities

Integrate drilling power with main platform systems

Reduce or decentralize drilling activity

Subsea separators

Combined typical weight savings = 30%

REDUCTION OF JACKET WEIGHT

Simplify geometry of the structure

Reduce wave loading by conductor "Shielding"

Aluminum mudmats

Reduced diameter members and bracing

Cast nodes

X-Bracing of jacket faces and conductor guides

Installation of jacket by SSCV tandem lift removes need for buoyancy tanks and/or trusses for barge launch stresses

Use of subsea pile drivers reduces pile guides and the need for followers

Combined typical weight savings = 50%

This combination of topside and jacket weight reduction is actively being pursued throughout the industry where conventional platform installation is the preferred development option. This particular platform currently under development in the North Sea would have cost in the order of 1.2 - 1.4 billion dollars in the technology of the day in the late 1970's. Its actual cost using today's technology is $700 million. (Figure 5)

In addition to the savings in the construction costs, a further significant saving is this complete topsides structure will be installed as one lift of approximately 7,000 tons.

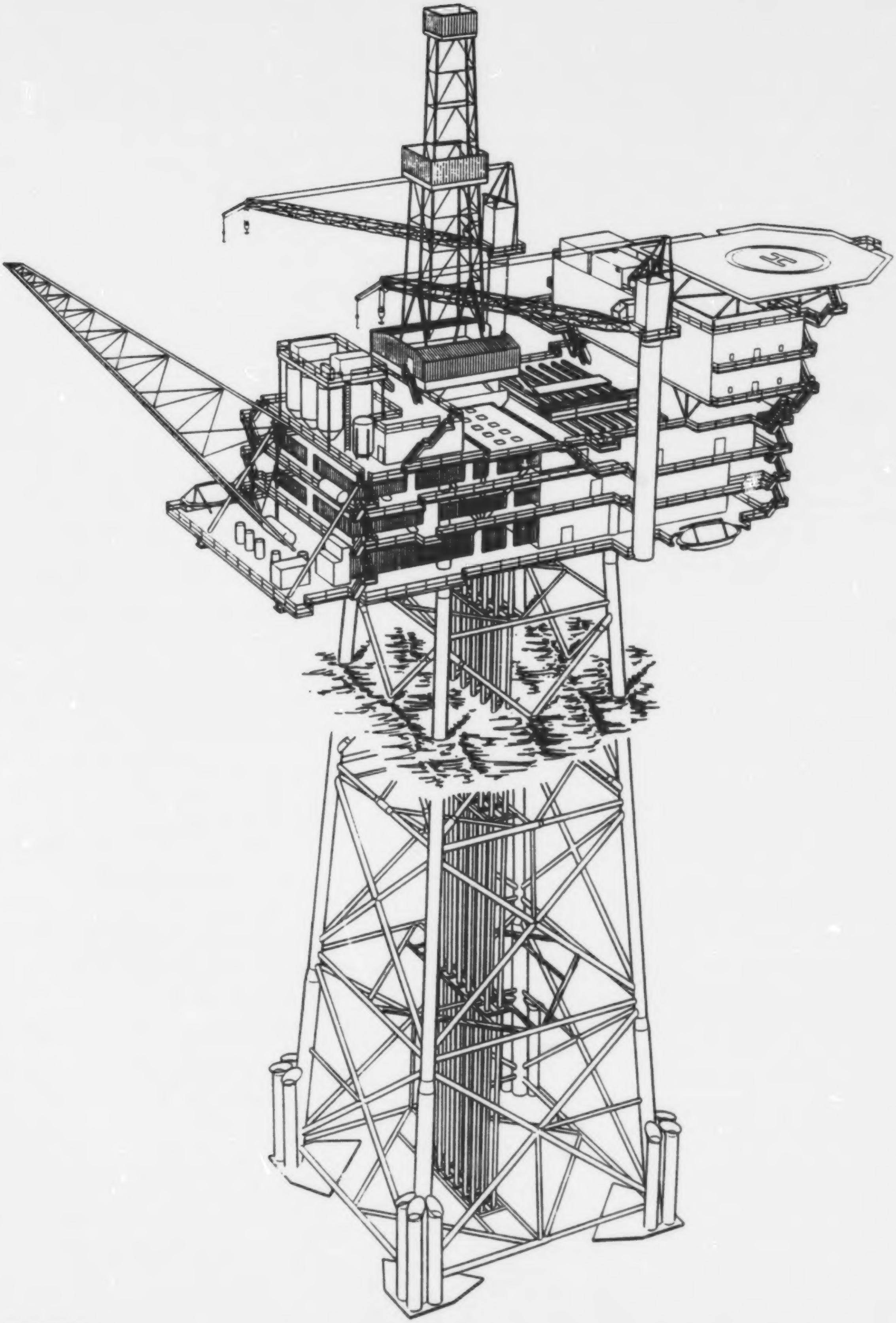


FIGURE 5

STREAMLINING INSTALLATION/HOOK-UP COMMISSIONING

In the days of conventional platform installation, it was not uncommon for construction barges to be on location for three or four months, lifting numerous modules while a crew of 600-1000 men may have been employed for a year or more in the final hook- up and commissioning of the platform. These hook-up personnel would be accommodated in a floatel moored alongside the platform at considerable day rates.

The costs of employing, transporting, feeding and providing for health and welfare of a man offshore is approximately 4-5 times that of his onshore counterpart. It is obviously in the operators interest to maximize the amount of work completed onshore and reduce the offshore installation and hoop-up phase to a minimum.

Offshore installation and construction contractors have been aware of this need, and have not been slow in responding.

This is one of the latest generation of semi submersible crane barges. Each crane is capable of lifting 6,000 tons or up to 12,000 tons in a tandem lift. Operators, aware of this capability, are now designing their platform topsides to meet the capacities of these super barges. This allows them to maximize their onshore hook-up and commissioning opportunities, in some cases even allowing complete platform topsides to be installed in a pre-commissioned condition. This lift, weighting approximately 5,300 tons is a complete integrated production deck for a southern basin gas field, seen here being lifted onto the SSCV in port prior to being taken offshore on the deck of the crane barge. The significance of this integrated deck was that within three hours of the deck being landed on the jacket, the generators were running and the module had its own power and light. Within the next few hours the accommodation module was lifted and set, with its beds made and ready for occupation.

(Figures 6,7,8,9 & 10)

FIGURE 6

FIGURE 7

FIGURE 8

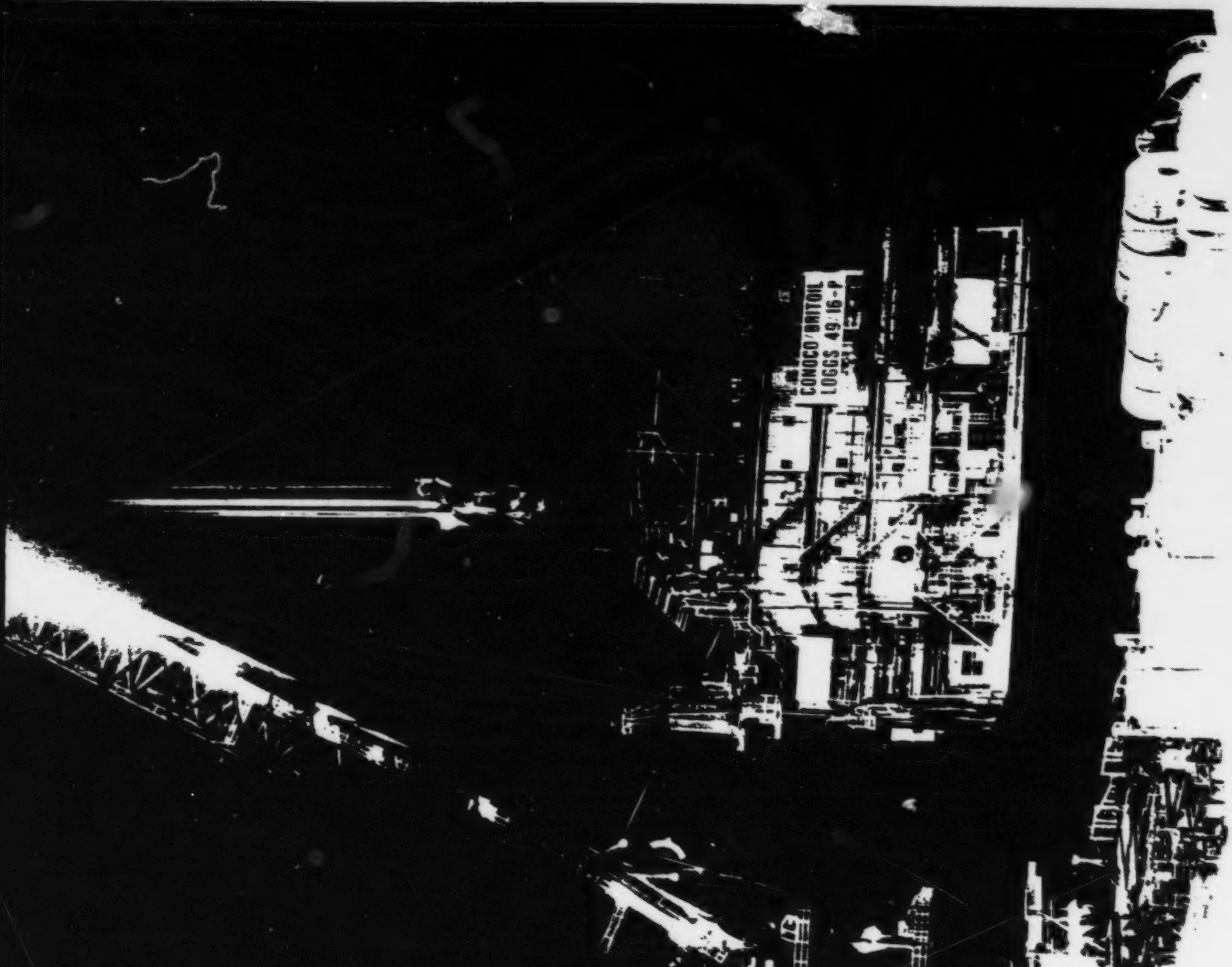
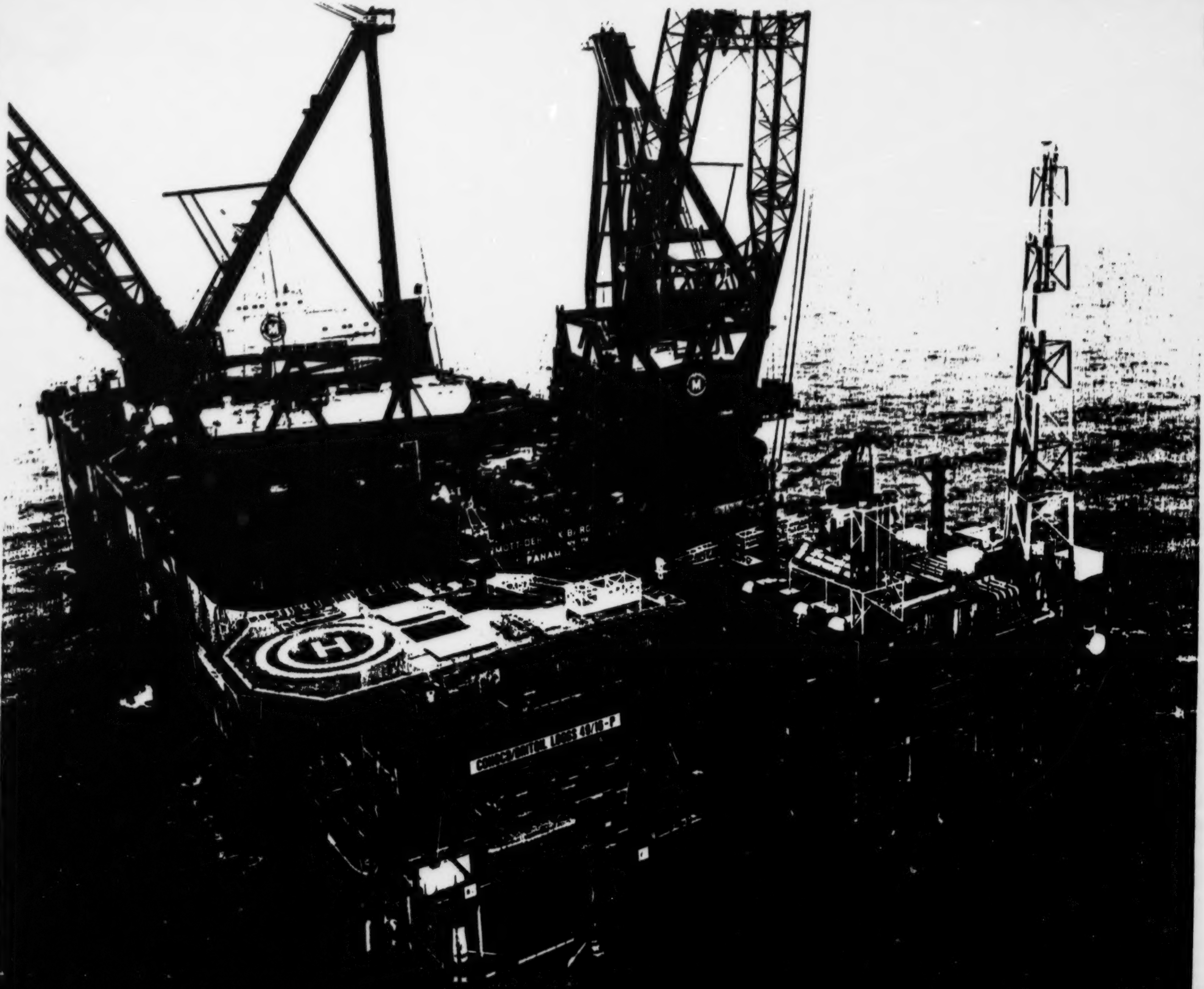

CONOCO/BRITOIL
LOGGS 49/16-P

FIGURE 9

FIGURE 10


CONOCO/BRITOIL LOGGS 49/16-P

Naturally, the services of these technological monsters does not come cheap, and the installation services are usually charged on a lump sum basis rather than day rate as in the past. This makes it easier for the cost engineers in arriving at their overall development costs. A further benefit to the operators is that because these barges are so efficient, their utilization figure is very low, thus creating a highly competitive situation between the barge owners.

So far we have looked at the various ways in which field development costs have, and are, being reduced when utilizing a conventional platform production philosophy, from which the reserves of the field are realized.

We will now look at an area of technology which, more than any other, has been driven ahead by the downturn of 1986.

INCREASED USE OF AUTOMATION AND DECENTRALIZATION OF DRILLING ACTIVITY

Field development from one centralized position places restrictions on the field design engineer, not only from a logistical and safety point of view, but also from the implications of the fields operational life. More importantly his access to the various payzone formations within the field area are limited and defined for him by his point of origin on the central platform.

A payzone being drilled from direction (A) gives him a completion length of only X metres. The same payzone drilled from (B) gives him the much increased completion length of Y. Given the freedom to drill into his payzones from unlimited positions around the field, his production rates and well performance can be substantially increased. Furthermore, his opportunities to horizontally complete are extended. (Figure 11)

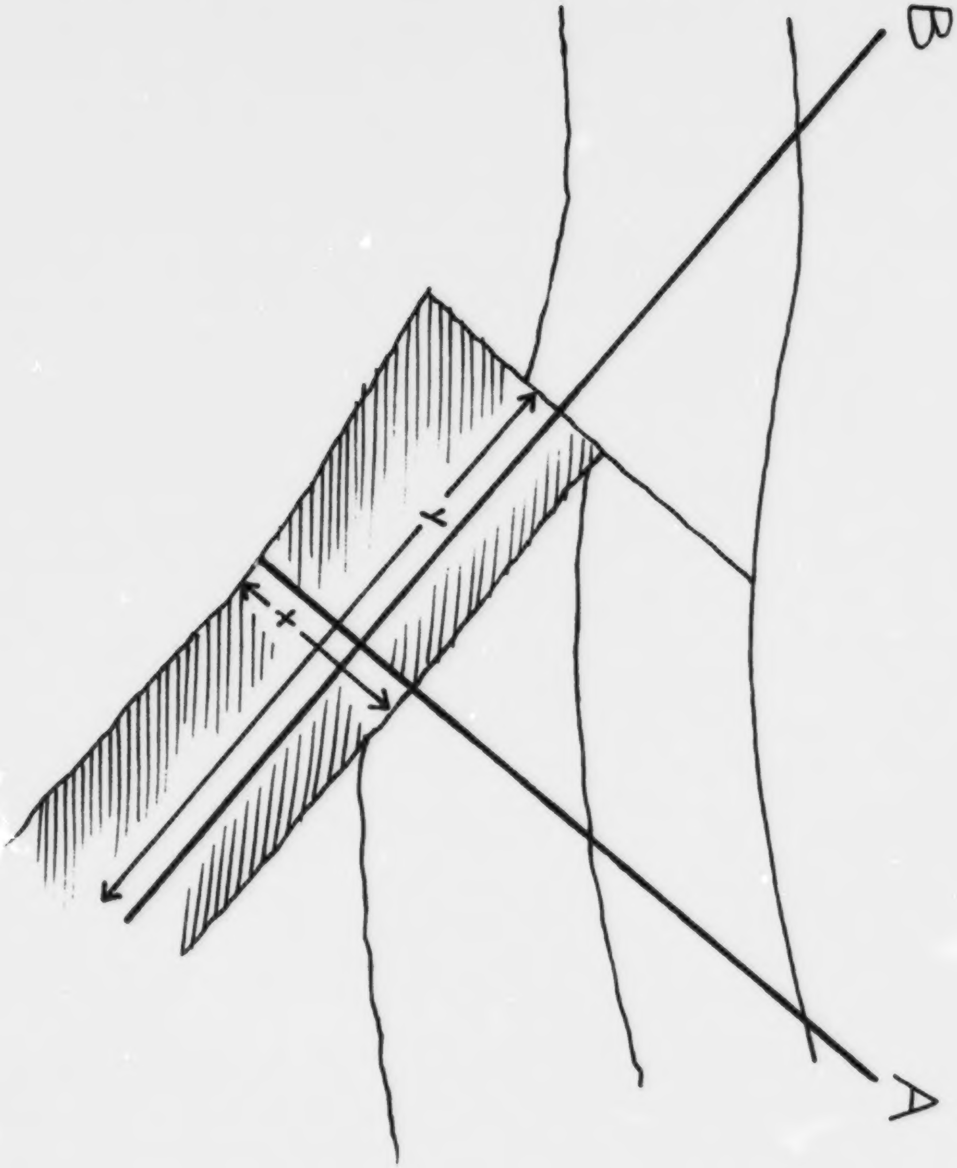


FIGURE 11

Decentralization of drilling can be achieved in two ways. The first and obvious solution is to install satellite platforms from which to operate, and this is indeed the option that has been used in the past. But it is an expensive option, and this expense has been greatly reduced by designing the platforms to be unmanned and as fully automated as possible, once remote drilling has been completed.

Because of the rapid evolvement of computer systems in the last few years, operators are turning more and more to automation in their drive to reduce manpower. Automated production control systems, safety shutdown systems and support system controls are all now available on the market. This gives the operator the opportunity to operate a number of unmanned satellites from one central platform. The central platform itself is controlled by telemetry from the beach, reducing enormously the amount of manpower required offshore in the operation of, and reporting on production equipment. (Figure 12)

This does not mean that the need for personnel is completely removed. Well trained technicians capable of operating and repairing the automation systems are essential. By reducing manpower by only 6 men, the operator obtains a saving of approximately $350,000 - $400,000 annually. This figure is sufficient to pay for a large and sophisticated automation system from the first years saving alone.

One further aspect of the reduction of manpower is the safety benefits. One does not like to dwell on the financial compensation details of victims such as those in the Piper Alpha disaster in which 167 men were killed. Nevertheless, operators face a double burden in incidents such as that, both from the loss of the asset and the massive sums now being pursued through the courts for victims of offshore accidents. A reduction in manpower obviously decreases his financial exposure in the event of these unfortunate incidents.

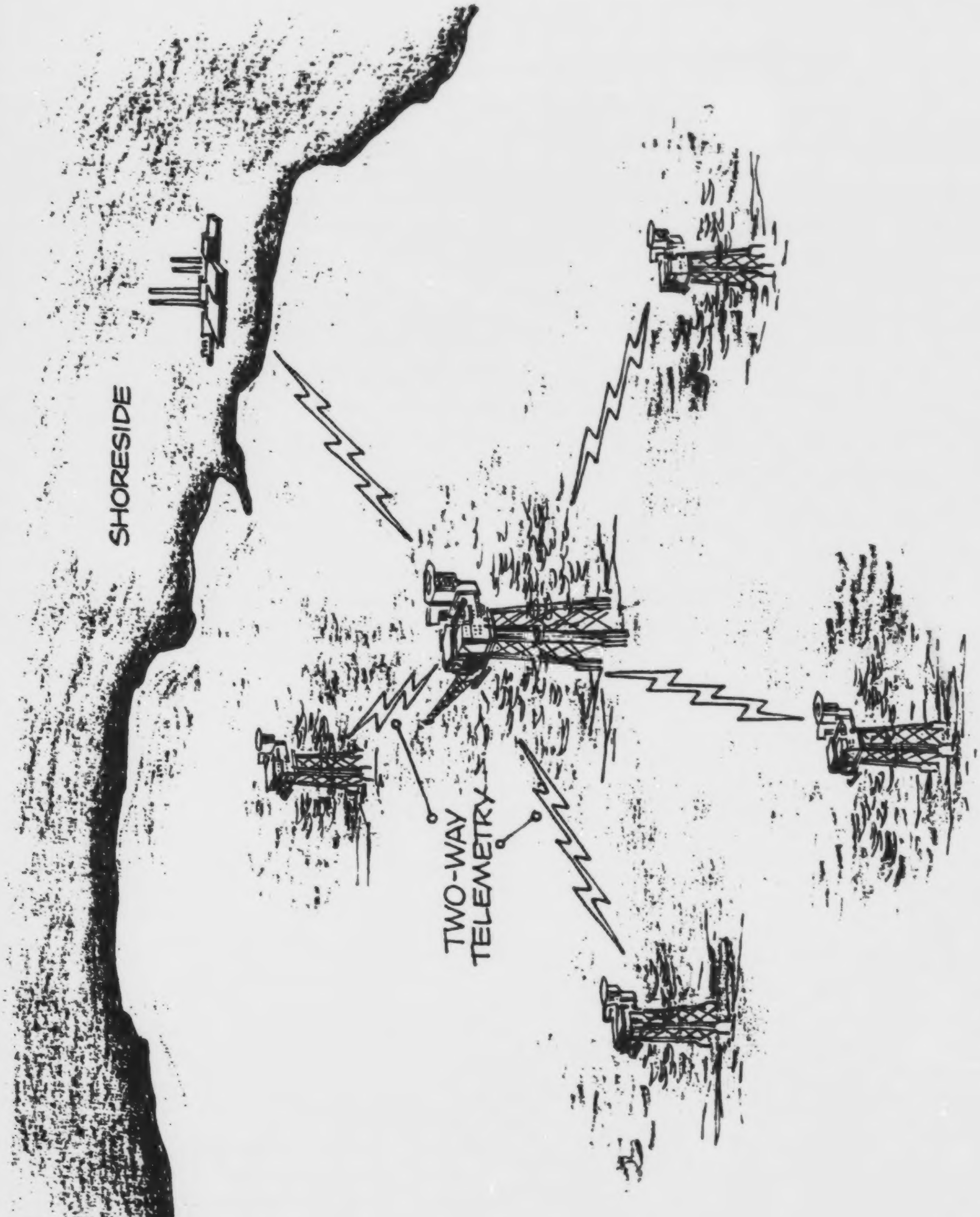

SHORESIDE
TWO-WAY TELEMETRY

FIGURE 12

Salaries, employee benefit packages, cost of transport to and from the field, and the cost of accommodating and providing for the health and welfare are all obviously reduced.

Since the economic pressures of the post 1986 environment, the second, and most significant option, is the subsea completion. (Figure 13)

Subsea completion technology has moved ahead rapidly in the past five years, and whilst it is beyond the scope of this paper to go into the technological details, we have reached the point today where subsea completions are an accepted, sophisticated and reliable tool in the field designers portfolio.

Between 1975 and 1990, 150 subsea wells had been completed in the UK and Norwegian sectors of the North Sea. The chart shows the dramatic increase in the number of subsea completions planned for installation between this year and 1995. (Figure 14)

Freed from his geographical restrictions, the field engineer is now able to deploy his well heads to maximize his field production. The production from these wellheads is then led back to the central platform via a series of subsea flowlines. (Figure 15)

Subsea completions also allow him to depart from the traditional platform concept, and the floating production facility is becoming a more and more accepted form of field development. This diagram shows a recently completed project in the UKCS, in which all development drilling was completed through templates and prior to manifold and flowline installation, and the whole subsea arrangement connected to a riser base manifold. from the RBM flexible risers lead up to the FPF for process prior to being exported via a remote SBM. (Figure 16)

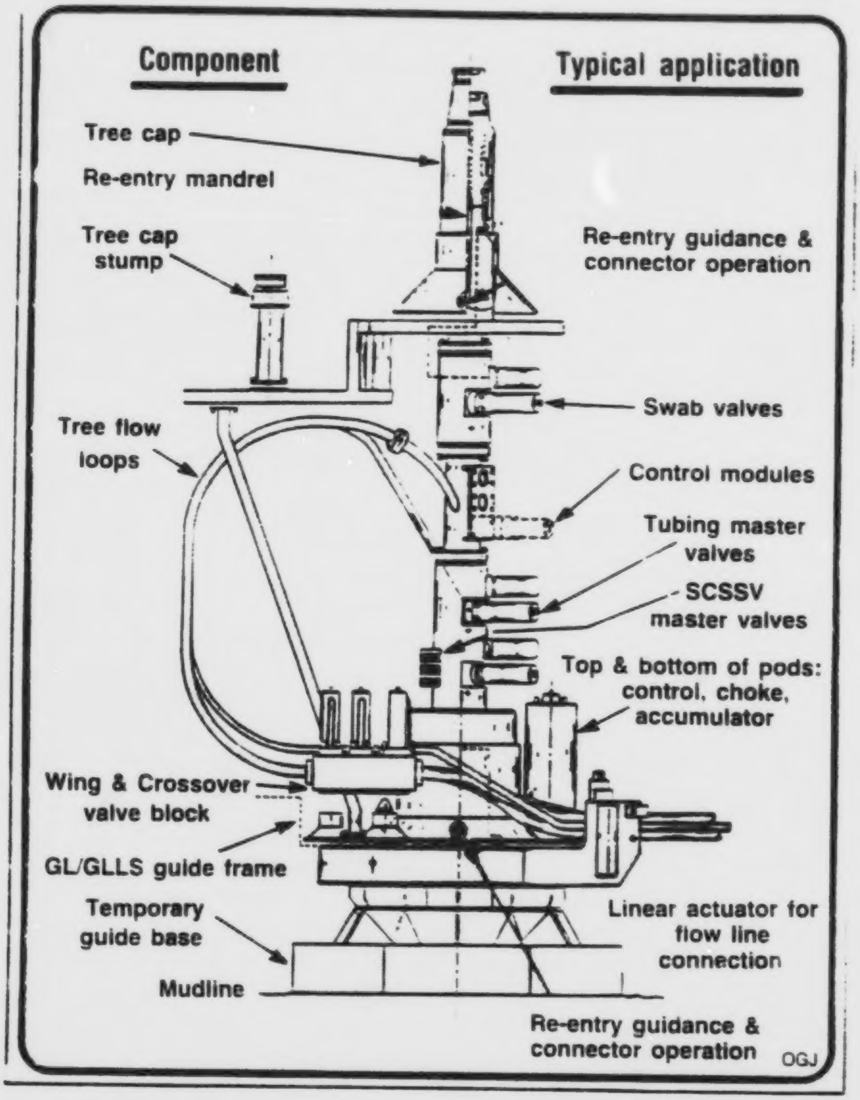
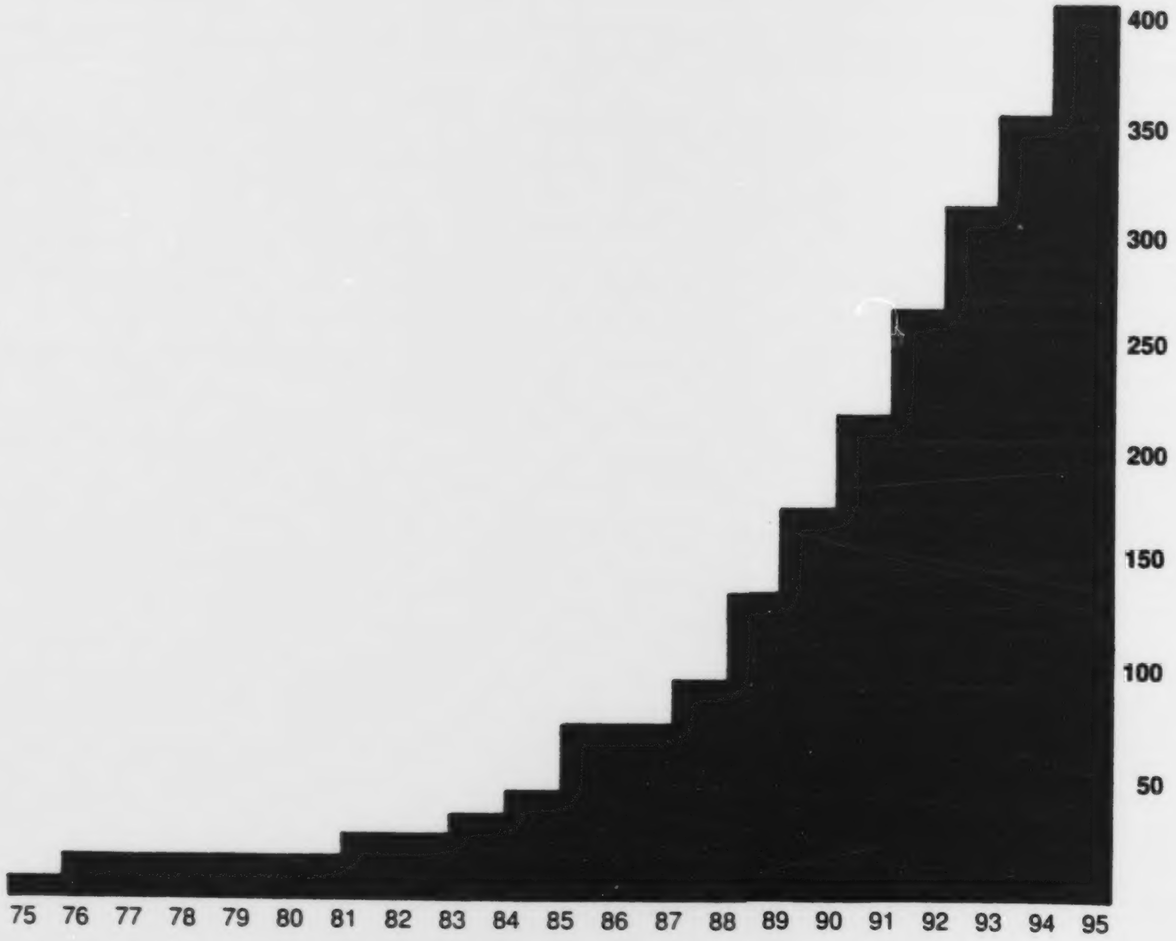

Component
Typical application
Tree cap
Re-entry mandrel
Tree cap stump
Re-entry guidance & connector operation
Swab valves
Tree flow loops
Control modules
Tubing master valves
SCSSV master valves
Top & bottom of pods: control, choke, accumulator
Wing & Crossover valve block
GL/GLLS guide frame
Temporary guide base
Mudline
Linear actuator for flow line connection
Re-entry guidance & connector operation
OGJ

FIGURE 13



SUB SEA COMPLETIONS

FIGURE 14

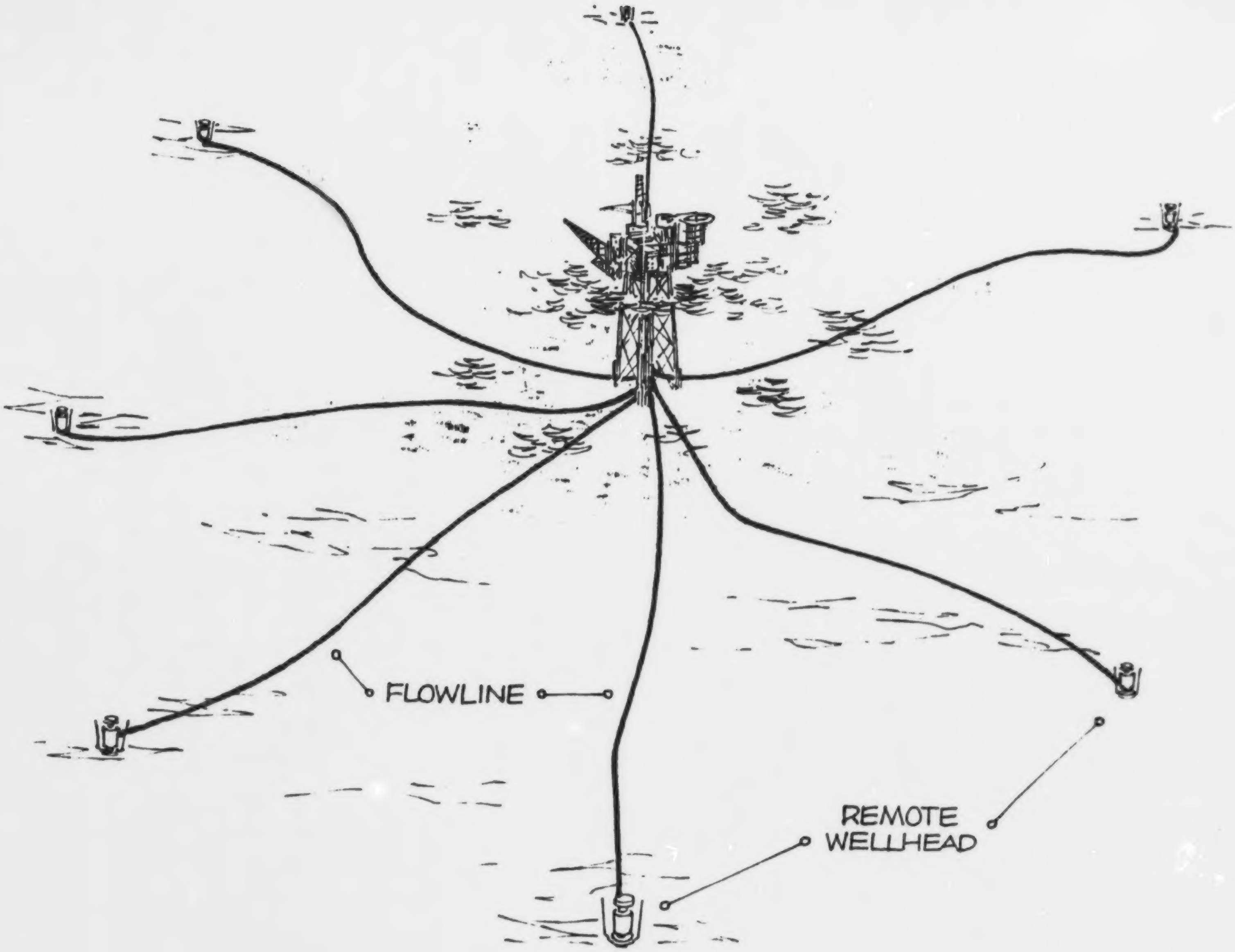

FLOWLINE
REMOTE WELLHEAD

FIGURE 15

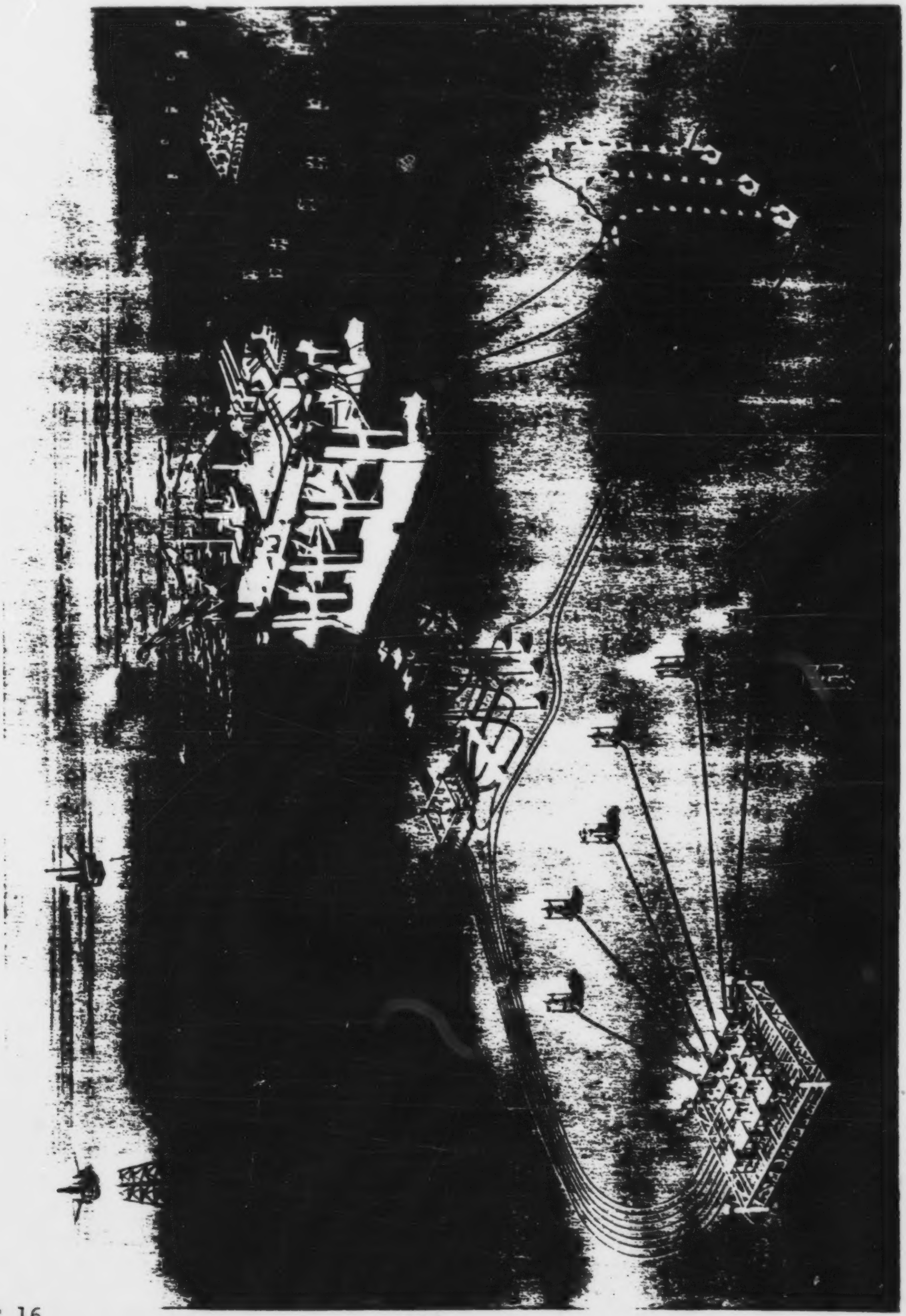


FIGURE 16

It is only a short step from here that the production platform can be done away with completely. A case in point is this field development presently underway in the UK. Situated 7 kilometres away from its parent platform, the field has been predrilled and by use of flowline bundle technology using integrated manifolds in the tow heads, is both water injecting and producing remotely. Although shown separately here, it is more usual to incorporate the control umbilicals within the flowline bundle. (Figure 17)

It will not be too far in the future before we see this system being extended so that the field can be operated from the beach hundreds of miles away.

Field maintenance and well workovers will be carried out on an AD HOC basis, by conventional semis as well as purpose designed work-over vessels, such as this modern generation of semi submersible DSVS. Incorporated into these manifolds and flowlines, and serving either single or multiple wells will be a novel piece of subsea technology also born out of the economic downturn of the late 1980's. (Figure 18)

Subsea separators, at present in embryo form, with one or two prototypes under trail, will become increasingly utilized to carry out production processes at present taking place topsides, and these bring into question the need for a topside facility at all. (Figure 19)

Considerable research is being carried out into this area of technology: This particular British prototype incorporates an integral pumping system. This achieves two objectives. Firstly, it reduces topside weight on the parent platform by negating the need for gas separation and process machinery - particularly valuable if the parent platform is a floater.

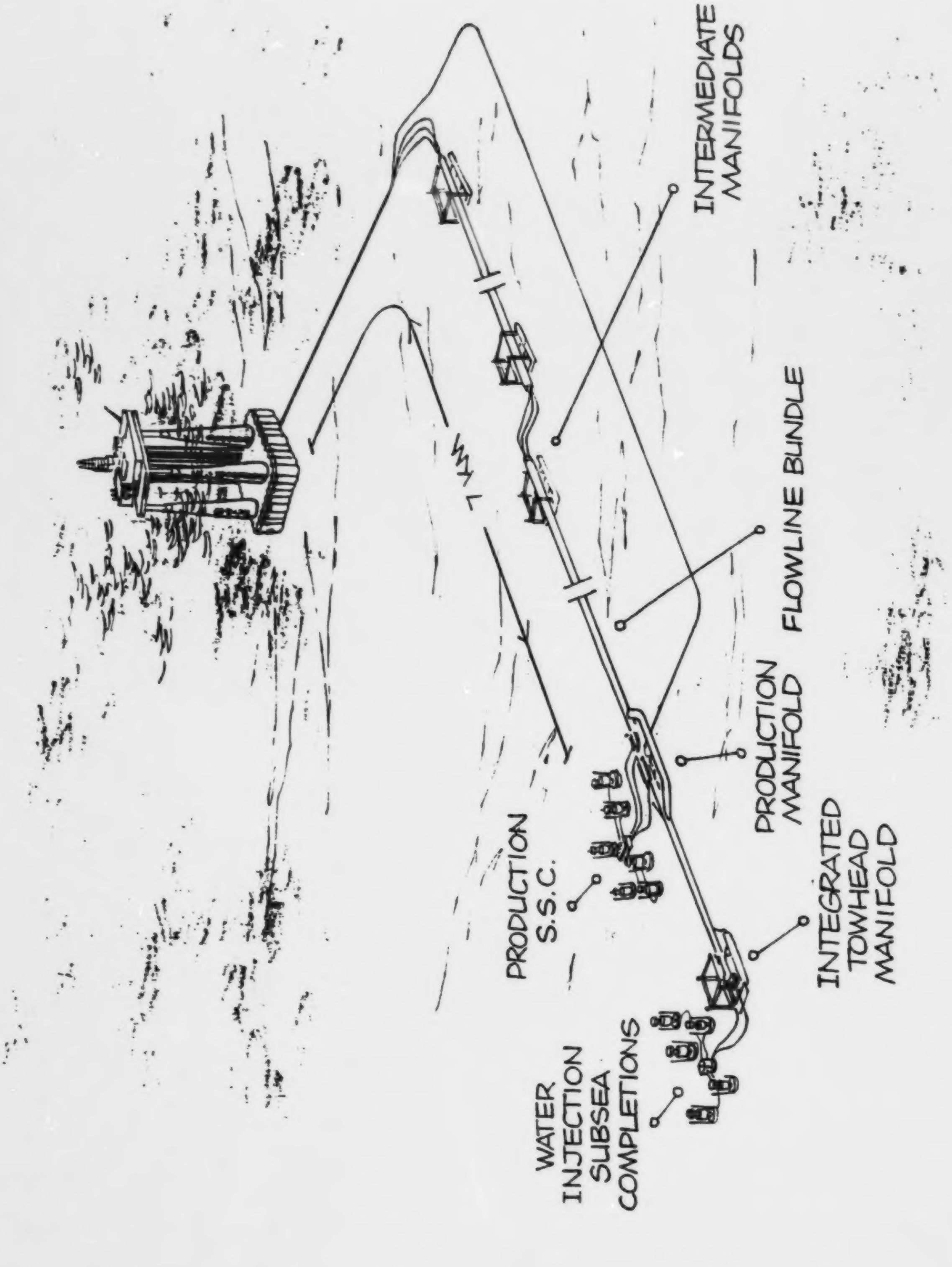

INTERMEDIATE MANIFOLDS
FLOWLINE BUNDLE
PRODUCTION MANIFOLD
INTEGRATED TOWHEAD MANIFOLD
PRODUCTION S.S.C.
WATER INJECTION SUBSEA COMPLETIONS

FIGURE 17

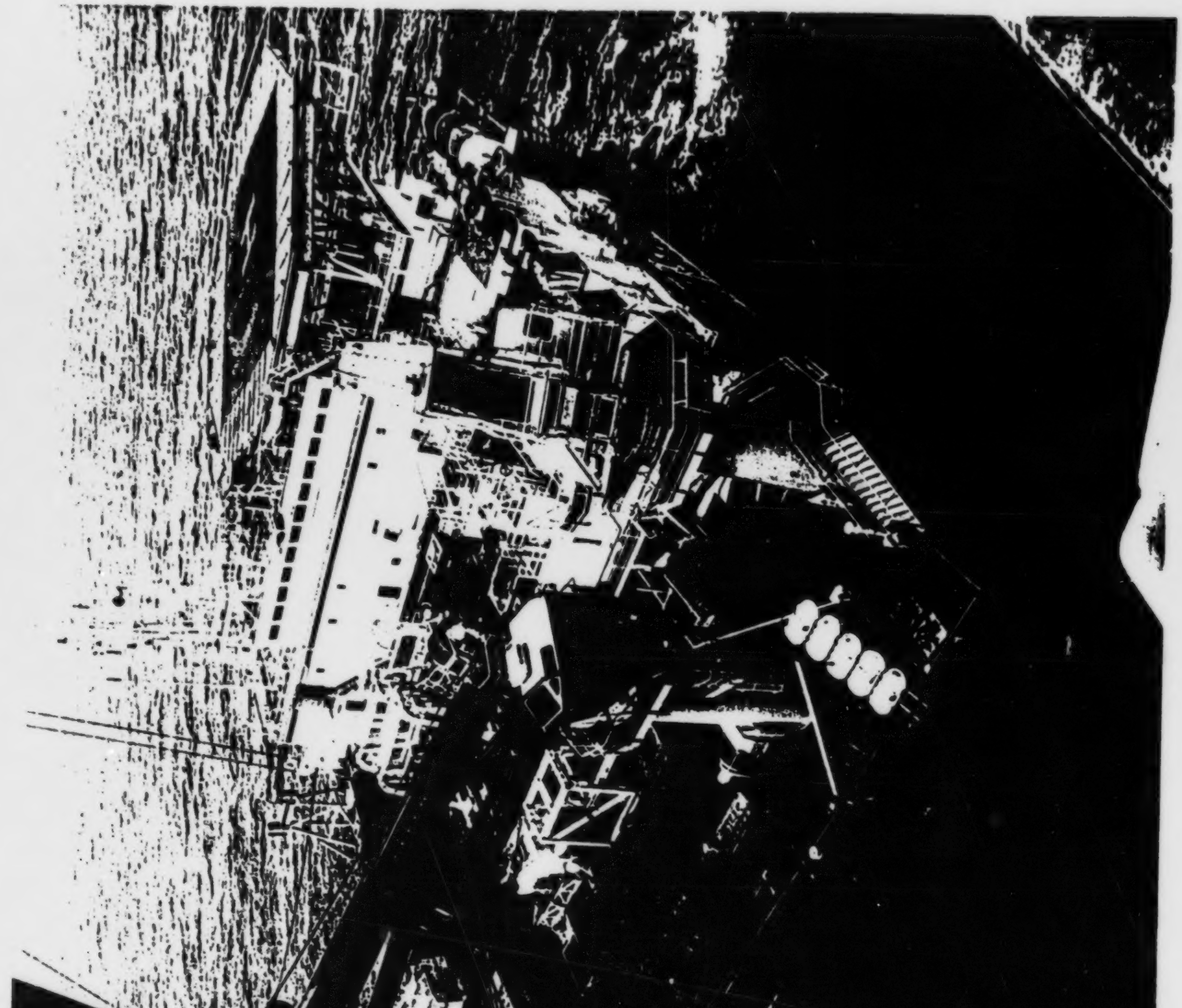


FIGURE 18

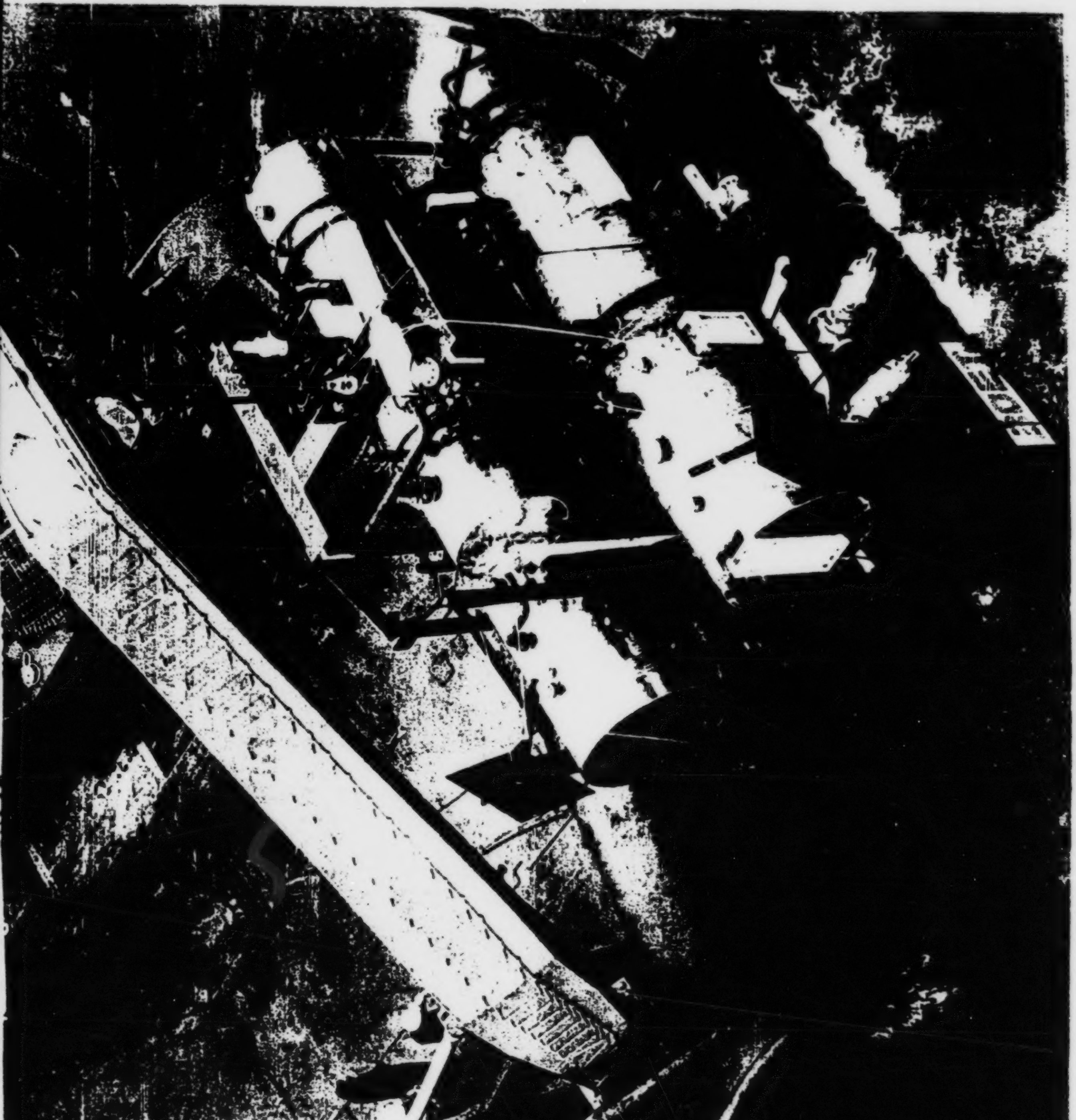


FIGURE 19

Secondly, because the pumps at wellhead level overcome the hydrostatic head to the surface facility, low pressure and depleting reservoirs production can be increased by an estimated 10 - 15%.

A Norwegian company meantime, is researching a single phased transport of produced hydrocarbons with a group of separators using only the pressure energy provided by the well flow. Viable transportation distances of up to 100 KMS are claimed. This distance could be extended almost indefinitely by the use of booster stations.

Provided reliability and ease of maintenance on these separators can be carried out cost effectively, this form of production facility will all but replace labour intensive and expensive topsides.

In conclusion, Ladies and Gentlemen, it is a combination of advanced and remote drilling techniques, lighter and smaller platforms, the increased use of automated systems, subsea completion and production technology which are allowing operators to stay in business in this new and uncertain economic climate. These advances, already underway prior to 1986 were rapidly accelerated by the oil price collapse.

Maybe Sheik Yamani did us all a favor in 1986 because it is not beyond the bounds of possibility that the oilfields of the 21st century will be operated and produced by a small team of technicians in a land based control room 200 or 300 KMS from the offshore location. (Figure 20)

And at that location, nothing will be visible above the ocean surface.

Thank You.

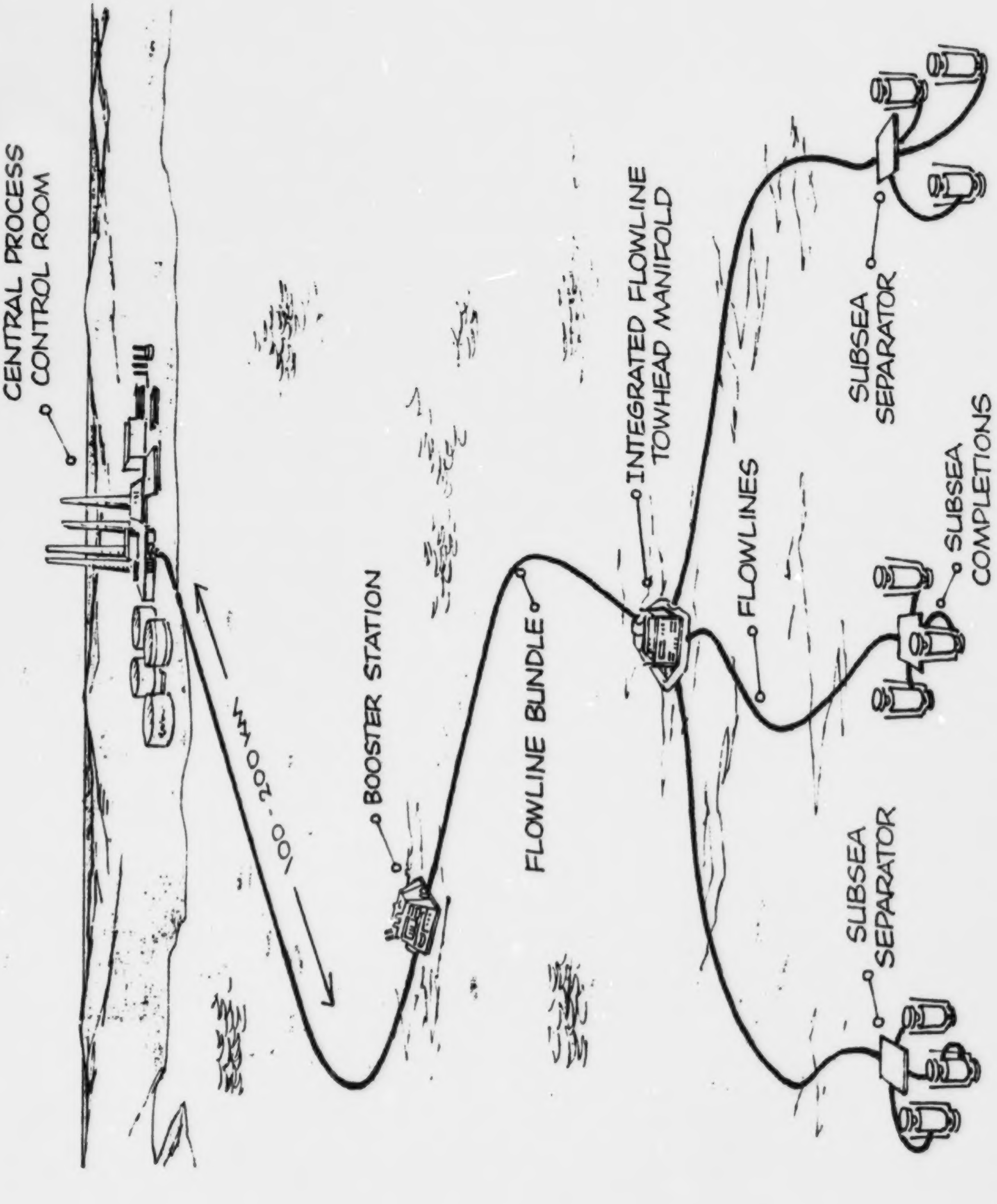

CENTRAL PROCESS CONTROL ROOM
100 - 200 km
BOOSTER STATION
FLOWLINE BUNDLE
INTEGRATED FLOWLINE TOWHEAD MANIFOLD
FLOWLINES
SUBSEA SEPARATOR
SUBSEA COMPLETIONS
SUBSEA SEPARATOR

FIGURE 20

SPEAKER : **TONY MACKAY**

COMPANY : **MACKAY CONSULTANTS**

LOCATION: **ABERDEEN, SCOTLAND**

TOPIC : **RISK MANAGEMENT AND OFFSHORE PROJECT COSTS**

BIOGRAPHY: Mr. Mackay is Managing Director of Mackay Consultants. Mr. Mackay attended the University of Kent at Canterbury and received his B.A. in Economics in 1968 and his M.A. in National and Regional Planning from the University of Reading in 1969.

From 1969-76 Mr. Mackay was Research Fellow, Department of Political Economy, University of Aberdeen. He lectured from 1976-81 at ISSPA, University of Aberdeen and was a Partner, Pelda (Economic and Planning Consultants) from 1979-84.

ABSTRACT

Offshore Field Development plans, and offshore exploration planning, are undertaken by oil companies in an environment of multi-dimensional uncertainty. The most obvious component of this economic environment of uncertainty is that of future oil prices. However, many other elements of the environment are also highly uncertain, including the costs of key services and equipment items, the fiscal regime and future technological advances.

A number of innovative approaches have been proposed, and adopted, in recent field development proposals where the oil company operator has spread the risk amongst other actors in the scenario. The current proposals for the development of the Hibernia field involve a substantial amount of the downside risk attaching to future oil price fluctuations being shared with the Canadian government. The development of the Emerald field in the North is due to be completed later in 1990, with both construction contractors and the contracted purchaser of the future oil production sharing substantial elements of financial risk with the field operator, Sovereign Oil.

The pattern of offshore development will change radically in the 1990s, as advances in subsea technology demand new commercial approaches. The extent of risk, and reward, sharing between oil companies and the supply and service sector could change as a result, and in certain circumstances result in an acceleration of offshore development activity levels. Some of the 'financial engineering' tools developed in international capital markets in recent years can usefully be applied to offshore contracting activities, offering the prospect of a more rational and efficient development of the market.

This paper briefly deals with a number of possible applications of such tools to offshore contracting, with a special emphasis on the implications for Canadian offshore development prospects.

Risk Management and Offshore Project Costs

Offshore Field Development plans, and offshore exploration planning, are undertaken by oil companies in an environment of multi-dimensional uncertainty. The most obvious component of this economic environment of uncertainty is that of future oil prices. However, many other elements of the environment are also highly uncertain, including the costs of key services and equipment items, the fiscal regime and future technological advances.

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The pattern of offshore development will change radically in the 1990s, as advances in subsea technology demand new commercial approaches. The extent of risk, and reward, sharing between oil companies and the supply and service sector could change as a result, and in certain circumstances result in an acceleration of offshore development activity levels. This paper examines the implications of two risk-sharing mechanisms, that may have relevance to the Canadian offshore scene, and draw on recent North Sea experience, namely:

(i) Financial Engineering possibilities;

and (ii) EPIC Contracting Trends

(i) FINANCIAL ENGINEERING

Over the last year or so it has become increasingly apparent that demand for semi-submersible drilling rigs in the North Sea from the early 1990s onwards is likely to outstrip supply, unless there is a rapid rate of new-building in the short term, or alternatively unless extensive investment is committed to extending the life of the existing rig fleet. This market situation is likely to transmit itself to the international level, and will impact equally on the Canadian offshore area.

Following the 1986 oil price plunge, and the consequent recession in North Sea exploration activity, day rates and utilisation levels for semi-submersible drilling rigs dropped substantially. Operating day rates at the beginning of 1986 were averaging $50,000-$60,000 per day. By the end of 1986, and throughout most of 1987, they were averaging $15,000-$20,000 per day. Semi-submersible day rates have only recently begun to recover this ground substantially, and day rates of $30,000-$40,000 per day are now being realised. Current utilisation levels are approaching 90% of marketed rigs in the U.K. sector and 85% in the Norwegian sector. It is worth noting that during a previous period of very high demand in the North Sea in the early 1980s, semi-sub day rates in the $90,000-$100,000 range were achieved for a short time.

Exploration and appraisal drilling is likely to continue at high levels in the U.K. sector during the early and mid 1990s. This will coincide with a period of growing demand for semi-submersible drilling rigs for the drilling of subsea development wells. This pattern is likely to be mirrored in the Norwegian sector over the same period.

A feature of North Sea rig utilisation in the early 1990s will increasingly be the requirement to deploy semi-subs on subsea development well drilling. This places new demands on rig capabilities, such as more extensive equipment lay-down areas, and the ability to carry and install the heavier items of well completion equipment characteristic of subsea development.

The estimated cost of building a medium specification, new semi-submersible drilling rig is $150 - $180 million. This compares with an estimated cost of $60 million a few years ago. As the shipbuilding industry internationally is expected to experience relatively high activity rates during the early 1990s, it is likely that further upward pressure on new-building prices could be experienced.

To undertake this level of investment, a drilling contractor would require something like a firm ten year charter at a day rate of around $120,000 (£80,000) per day or more. As they do not expect to achieve this degree of market commitment from client, or oil, companies, new-building is not considered a feasible short term option. Consequently, some drilling contractors are giving serious consideration to the options available for the enhancement or modification of their existing fleets.

The crucial question is whether the drilling contractors, after four years of marginal, if not negative, operating margins, are in a position to undertake this investment. In the absence of a firm long term charter at a day rate somewhere in excess of $40,000 per day for a medium specification semi-submersible built in the 1970s, it is unlikely that a contractor will invest in rig life enhancement. It is equally unlikely that many oil company managers will propose a long term charter at these rates. Consequently, the prospect of a supply shortage, and escalating day rates leading to escalating exploration and, increasingly, field development costs is very real.

One solution could be a greater degree of equity participation by the oil companies in rig ownership/operation. This would not be a completely new development for the industry, as this has happened in the past. However, it is questionable whether this is the optimum division of specialised functions between oil companies and drilling contractors, and it certainly doesn't guarantee maximum commercial efficiency in the rig market.

The current market response - speculative acquisition of drilling rigs and/or drilling contractors, by strongly capitalised companies from outwith the drilling sector - is unlikely to produce a long-term re-structuring of the industry. Much of the acquisition activity apparent during the second half of 1989 resembles asset play, rather than long term investment. This does little to ensure the optimisation of operational efficiency in the drilling sector. Any measure of operational efficiency in this sector should encompass well performance, safety and financial performance. High performance in these areas requires the specialised, professional management capability of contractors with a long-term commitment to the industry.

A Question of Financial Risk Management

From an economist's perspective, the problem confronting the drilling contractors and the oil companies is one of managing uncertainty with regard to the future economic environment. It is probable that the perceived environmental risk factors (e.g. expected future day rates) are subject to equivalent expectations on the part of both parties. However, in one sector, drilling contractors, capital is severely constrained, while this is significantly less of a constraint for the other sector. The rational investment response is not forthcoming as the structure of the industry is such that it falsely signals a capital rationing situation.

instruments such as futures and options contracts have been developed to allow companies in other sectors to manage risk of this type. An example of a hypothetical rig hire option contract, designed to encourage the investment in rig life enhancement discussed earlier, is provided below. This is highly simplified for the sake of illustration, but serves to demonstrate the risk sharing, and investment promoting, features of this instrument applied to this problem.

The assumptions used in this illustration are:

(i) The option applies to a five year rig hire contract (365 days/year) at a day-rate of $40,000 per day, with contract execution at a stipulated date in the second half of 1990.

(ii) The rig is a third generation semi-submersible to be converted at the rig contractor's cost between option contract signing (early 1990), and option execution, at an estimated cost of $15 million.

(iii) The option contract stipulates a liability on the part of the oil company to pay the rig contractor a lump sum of $15 million in the event of not exercising the charter option on the execution date.

(iv) The oil company will value the cost of the $15 million potential liability as the cost of repaying a loan of this amount at market interest rate, i.e. at 15% APR over five years this is around $11,300 per day.

(v) The rig contractor's operating cost level is around $28,700 (including financial costs) per day, and at prevailing market rates below this level the rig will not be marketed.

(vi) The prevailing "equivalent rig" long-term charter day rate at date of option execution coincides with expected average rates over a five year contract period.

(vii) The oil company will exercise the option as long as prevailing day rates are above $28,700 per day (i.e. contract day rate less potential daily cost of not exercising option).

The pay-off graphs for the oil company and the rig contractor respectively under this option contract are illustrated in Figures 1 and 2 below:

(Figure 1)
(Figure 2)

FIGURE 1

PAYOFF GRAPH,
OIL COMPANY

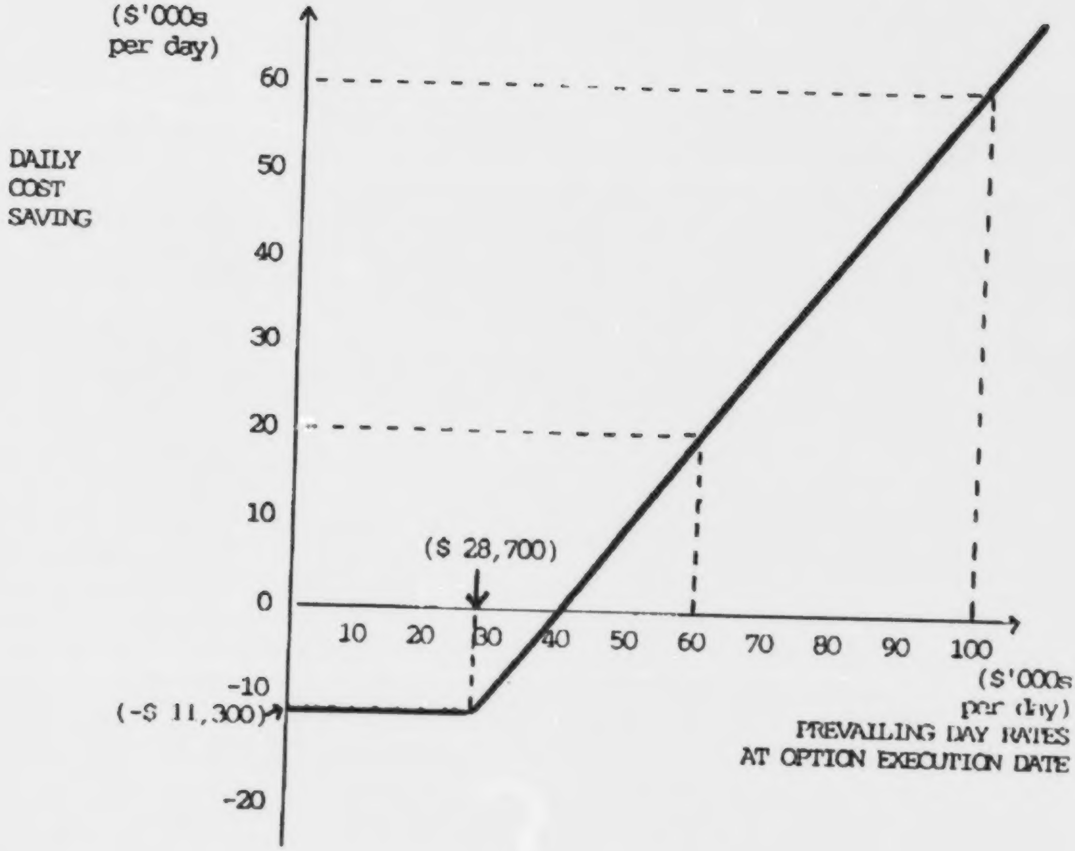
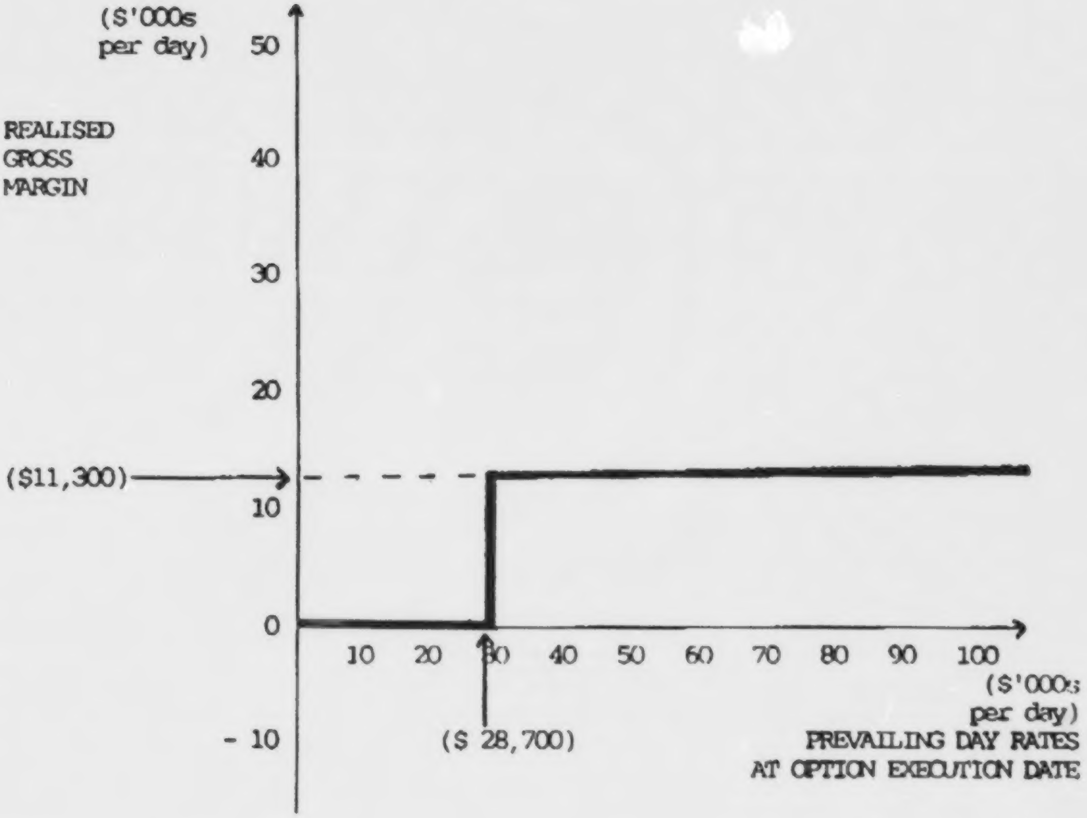


FIGURE 2

PAYOFF GRAPH,
DRILLING CONTRACTOR



The pay-off graphs show the way in which the mechanism removes the bulk of the down-side risk for the rig contractor, at the price of his upside potential. For the oil company, some additional, but limited, downside risk is taken on in return for a high upside potential. The mechanism also provides a buffer, ranging between market day rates of $28,700 to $40,000, where both parties are partially isolated from market fluctuations.

The option contract parameters can be refined to meet the requirements of a particular situation. For instance, some of the upside potential could be shared by the oil company with the drilling contractor. Also, tax considerations on the part of the operator could substantially alter the shape of the pay off graph where the rig is to be used for field development well drilling. It should be noted that the initial commitment approval by oil company managers is limited to a potential $15 million (gross of tax) as opposed to the full contract value, with managers retaining the flexibility on the larger commitment until the option execution date.

The techniques required to measure corporate requirements, and design a negotiating strategy for this type of contract, are widely applied by economists in other applications, and could equally well be adapted to rig contracting. Any failure to address the issue of market efficiency in this sector will have wider national economic implications in the nineties than might have been the case in the past, as mobile rigs are increasingly required to develop offshore production capacity, in addition to exploring and appraising.

(ii) EPIC CONTRACTING

EPIC or non-EPIC contracting philosophies will be a key issue in 1990 for a number of North Sea operators, and is likely to become equally pertinent to the Canadian offshore scene.

There has been a trend in recent years towards the award of turnkey contracts by oil companies for smaller offshore field developments, especially subsea developments. Typical of these contracts are EPC (Engineering, Procurement and Commissioning) contracts or EPIC (Engineering, Procurement, Installation and Commissioning) contracts. One interesting recent example was Sovereign's award of such a contract for the development of the Emerald Field. This field is scheduled to come on stream in the third quarter of 1990, and progress is being monitored closely.

However, it is becoming clear that fewer oil companies favour this contracting philosophy than might have appeared to be the case a year or two ago. The arguments against EPIC contracting for these companies include:

i) key engineering elements of oilfield development have long-term maintenance implications for the operator, and require an engineering input from this source at the development phase;

ii) standardised operational procedures with operating companies demand direct engineering input to the development phase;

iii) for maximum commercial efficiency certain elements of the development phase package require to be retained as separate contract packages (e.g. design engineering and fabrication);

iv) larger oil companies view their in-house engineering capability as a strategic resource and a competitive strength, and will seek to ensure employment of this resource in field development engineering whenever possible.

Against these points, the following arguments can be put in favour of EPIC contracting:

i) there will always be a strong incentive for the smaller independents (e.g. Sovereign in U.K., Saga in Norway and possibly LASMO in Canada) to adopt an EPIC philosophy;

ii) if subsea technology development has now plateaued, and the engineering design component will become routine, then EPIC contracting may be reconsidered by those companies who are currently opposed;

iii) recent joint venture and merger activity in the subsea engineering related sectors suggests an expectation of greater emphasis on EPIC contracting for subsea field developments. The Vetco/Kvaerner/FSSL tie-up is possibly an example.

The most likely, though by no means certain, outcome is that the major oil companies avoid EPIC contracting, while the smaller North Sea operators and independents adopt the philosophy by necessity, i.e. shortage of internal management and engineering resources.

The implications for the oil-related engineering and equipment supply sectors are potentially significant. There is reasonable grounds for arguing that a large part of the U.K. supply content, and similarly in Canada, of offshore spending is relatively low technology, with the high technology content being retained within the international oil companies and major international project design contractors. A higher degree of EPIC contracting offered the opportunity to break this mould, and build up a higher level of oilfield technology capability in the U.K. The Emerald contract is a good example of this.

This aspect is especially relevant for host country capability, as the growing importance of subsea technology offers the prospect of a greater proportion of engineering design and project management work being carried out in the host country or province.

This issue deserves to be monitored closely during 1990, and once again the significance of a strong independent operator presence in the offshore sector in both Canada and the U.K. is apparent.

CONCLUSION

I hope you will have found the discussion of these aspects of risk management in offshore operations of interest. Both issues, and indeed the general issue of risk sharing between oil companies and their contractors, may well develop rapidly over the next few years, in the relatively young Canadian offshore market.

Angus Nicolson/Tony Mackay
Mackay Consultants

May 1990

SPEAKER : TOMM LUND

COMPANY : AKER ENGINEERING a.s.

LOCATION: OSLO, NORWAY

TOPIC : THE CONCEPTION AND DEVELOPMENT OF THE REVISED HIBERNIA DECK CONFIGURATION

BIOGRAPHY: Tomm Lund is Manager, Topsides and Drilling Facilities with Aker Engineering a.s.

Mr. Lund has a B. Sc. in Mechanical and Process. He has obtained experience in Supervisory and Management (10 years); Piping and Layout (9 years); Multidiscipline work and overall platform topsides development (6 years); and Project Management and Business Development (5 years).

ABSTRACT

THE CONCEPTION AND DEVELOPMENT OF THE REVISED HIBERNIA DECK CONFIGURATION

The paper will describe the terms of reference from which Aker Engineering performed the concept revision study from October 1988 to June 1989, and describe the approach to the work which led to a saving of approximately 25% of the original weight.

The new design will be described in detail with respect to:

- structural systems
- platform arrangement
- safety
- construction and installation methods
- weight saving potential relative to original concept

Emphasis will be put on the fact that although departing somewhat from traditional topside designs, the new concept only employs well proven system design and construction methods in a new way.

THE CONCEPTION OF THE NEW HIBERNIA TOPSIDES

The optimisation studies carried out by Aker Engineering, for field operator Mobil Oil Canada, on the Hibernia Platform, resulted in a new topsides concept which weigh in at 32,000. This slices more than 10,000 off the previous design and produces very significant cost savings in both topsides and the four-legged concrete gravity substructure.

The knowhow needed to achieve reductions of this magnitude has come from focusing efforts in this area over the past few years by applying well proven technology in a new manner.

Following the slump in oil prices in '86, Aker began a series of internal studies looking at ways to reduce the large topsides typical of many North Sea platforms. We considered all factors influencing the size of existing topsides - for example process systems complexity, equipment redundancy, manning levels, supply ship activity and, of course, the structural design and materials of construction - and found that we could reduce costs by as much as 50 %. Simplification was the keyword.

In the case of Hibernia, we saw a large potential for optimising the then current conceptual design, which was based on a traditional module support frame, cellar deck and twenty modules. So we presented our thoughts to Mobil in St. John's in September 1988 and won the change to prove our optimisation techniques in a three month study to update the topsides concept.

The objective was not only to reduce overall complexity and cost but also to lower the centre of gravity of the topsides. This in turn would help reduce the stability and buoyancy required from the gravity base, making transportation far less critical to be performed.

First conclusion reached in the study was that major savings could be made simply by arranging the topsides in fewer modules, retaining the modular and support frame arrangement. Five large main modules, lifted onto the MSF, resulted in savings of upto 5000 t in topsides weight.

But Aker took the optimisation one step further. By integrating the MSF function into the modules and joining them together as a type of integrated deck before floatout and installation, the MSF would no longer be needed. Lifting could be omitted as a module design loadcase, and heavy lift vessels became unnecessary. Weight savings were doubled knocking out a quarter of the original topsides weight.

After a second and more detailed phase of the optimisation by Aker completed last summer, the "supermodules" idea was proven to Mobil's satisfaction and has now been accepted as the design concept for Hibernia's topsides.

The key feature which makes the new design possible is the inclusion of structural bulkheads on two sides of each module, similar to those employed in shipbuilding. Adjacent bulkheads are welded together to produce a 1,5 m wide box structure - strong yet lightweight, similar to a supertanker.

In relation to the four 17 m diameter octagonal concrete shafts supporting the topsides, the three central modules - wellhead, drilling and utilities - are sized so that the four intermediate bulkheads are sited above the shafts, running transversely across the width of the platform. The two end modules - process and accommodation, each with a bulkhead on one side only - hang outboard the shafts.

Current thinking is that the topsides is likely to be assembled on a specially built concrete pier on the coast of Newfoundland. Each finished module will be skidded into place and the bulkheads welded together. The completed topsides will then be transported on two barges, and mated to the gravity base in protected waters inshore, before being towed to the field. With the previous 20 module design, mounting the modules on the MSF would have required a heavy lift vessel, in turn requiring dredging, or even rock removal at the assembly site to achieve the draught required for the heavy lift vessels.

The design concept not only combines strength and stiffness into a single integrated structure, whilst retaining the advantage of multi-site fabrication of modular deck elements, it has also provided the chance to develop structural systems which have more than one function.

The space within the bulkheads is used for storage of water, diesel or other fluids. This not only saves on weight and space, but also increases capacity, reducing resupply frequency - an important consideration in waters which are prone to becoming icebound. In safety terms the bulkheads also provided improved fire and blast protection.

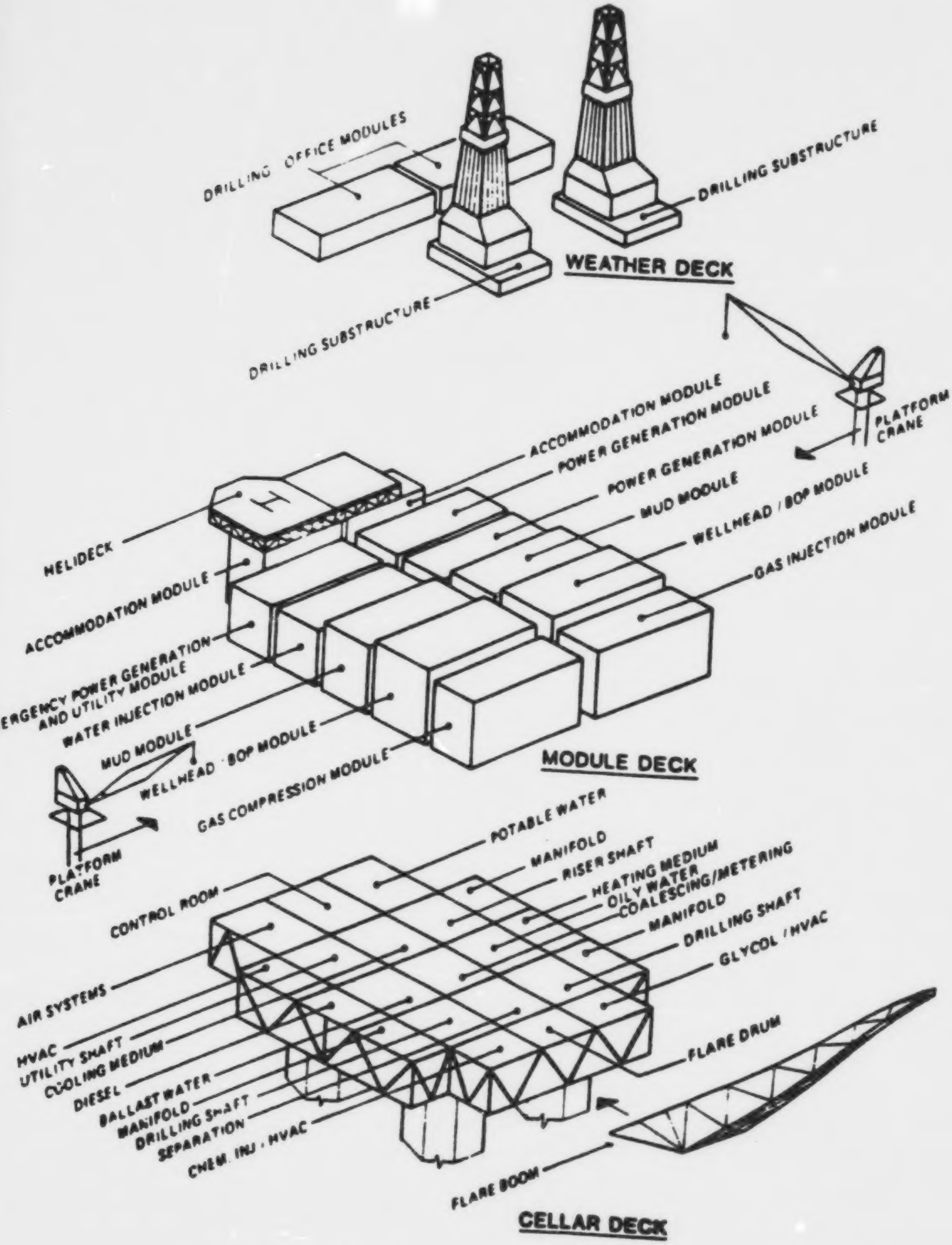
The use of large modules has also yielded other benefits. Greater flexibility in general layout has meant that equipment can be located more logically, following the processing sequence, and dispenses with some of the open areas previously present. Detailed piping studies of areas with high equipment density have been run to check on accessibility for maintenance, in addition ensuring that problems will not be experienced with sequencing of equipment for delivery and installation. As the larger modules contain complete systems, precommissioning can in many instances be completed at the module construction site. This will reduce precommissioning at the assembly site. Because the total topside will be completed before mating, precommissioning of systems at the inshore and offshore sites will be drastically reduced.

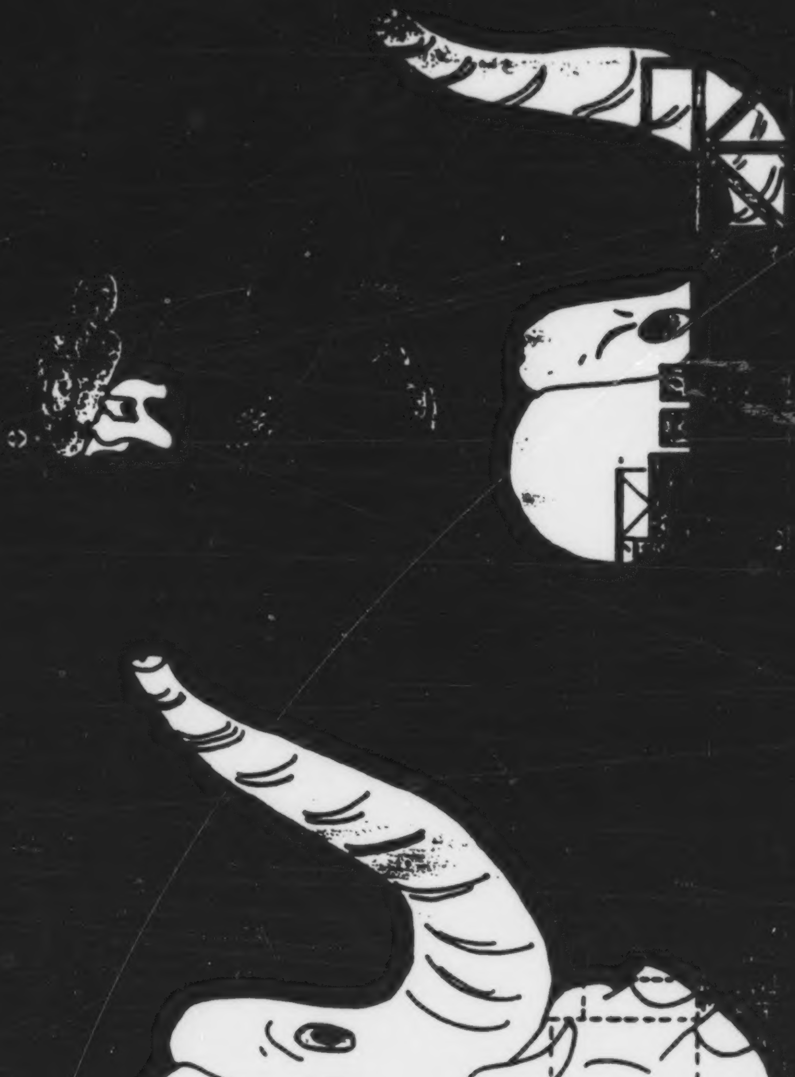
As a result of these and other measures, overall volume of the topsides is 25 % less than that of the original design concept, although Aker is keen to emphasis that safety has in no way been compromised and in fact has been improved.

The process module and living quarters have maximum separation and the added protection of the four bulkheads. There are two continuous escape routes at two levels, all hydrocarbon areas are naturally ventilated and risk analyses have confirmed that platform integrity would be maintained in a number of accident scenarios, including catastrophic events such as the complete loss of process and wellhead modules.

Cost savings associated with the new look design for Hibernia are said to be very significant, although these remain undisclosed. As a partner in the Newfoundland Offshore Contractors consortium, Aker is currently bidding against two other consortia for the detailed topsides engineering contract, which it is hoped will be awarded this summer.

HIBERNIA, CONCEPT PRIOR TO 1988 STUDY


DRILLING OFFICE MODULES
DRILLING SUBSTRUCTURE
WEATHER DECK
DRILLING SUBSTRUCTURE
ACCOMMODATION MODULE
POWER GENERATION MODULE
POWER GENERATION MODULE
PLATFORM CRANE
MUD MODULE
WELLHEAD / BOP MODULE
GAS INJECTION MODULE
HELIDECK
ACCOMMODATION MODULE
EMERGENCY POWER GENERATION AND UTILITY MODULE
WATER INJECTION MODULE
MUD MODULE
WELLHEAD BOP MODULE
GAS COMPRESSION MODULE
MODULE DECK
PLATFORM CRANE
POTABLE WATER
MANIFOLD
RISER SHAFT
HEATING MEDIUM
OILY WATER
COALESCING/METERING
MANIFOLD
DRILLING SHAFT
GLYCOL / HVAC
CONTROL ROOM
AIR SYSTEMS
HVAC
UTILITY SHAFT
COOLING MEDIUM
DIESEL
BALLAST WATER
MANIFOLD
DRILLING SHAFT
SEPARATION
CHEM. INJ. HVAC
FLARE DRUM
FLARE BOOM
CELLAR DECK



HIBERNIA TOPSIDES CONCEPTUAL STUDY

STUDY OBJECTIVES

REDUCE WEIGHT, COST AND LOWER CENTER OF GRAVITY

BY

1- MODIFYING MSF CONFIGURATION

2- UTILIZING LARGER MODULES

3- EVALUATING ALTERNATIVE PROCESS/UTILITY EQUIPMENT

4- IMPROVING LAYOUT

5- INVESTIGATING ALTERNATIVE DESIGN/CONSTRUCTION CONCEPTS

HIBERNIA TOPSIDES CONCEPTUAL STUDY

GENERAL DESIGN CONCEPT

- ELIMINATE MSF
- ELIMINATE MODULE LIFTING
- REDUCE OVERALL WEIGHT BY DEVELOPING STRUCTURAL SYSTEMS WITH MULTIPLE FUNCTIONS RATHER THAN DESIGNING SEPARATE SYSTEMS FOR EACH FUNCTION

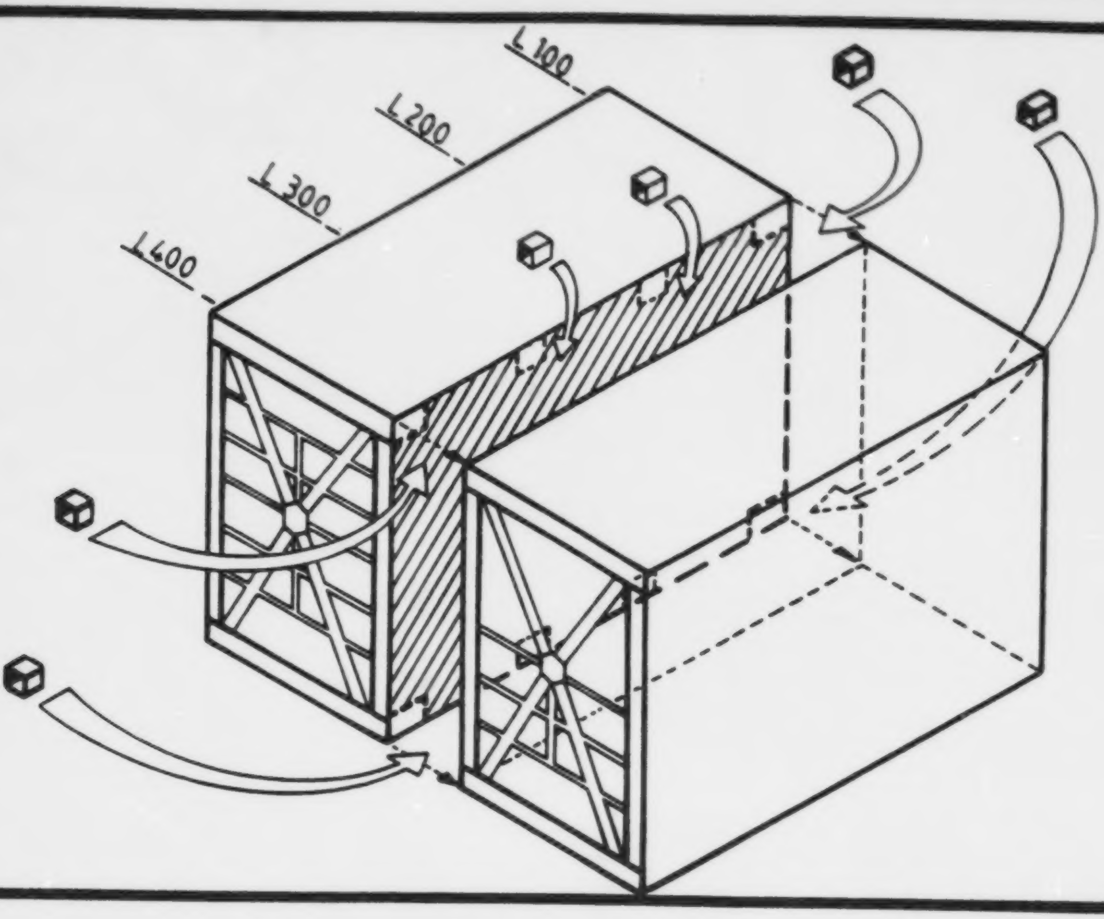
GENERAL DESIGN OBJECTIVE

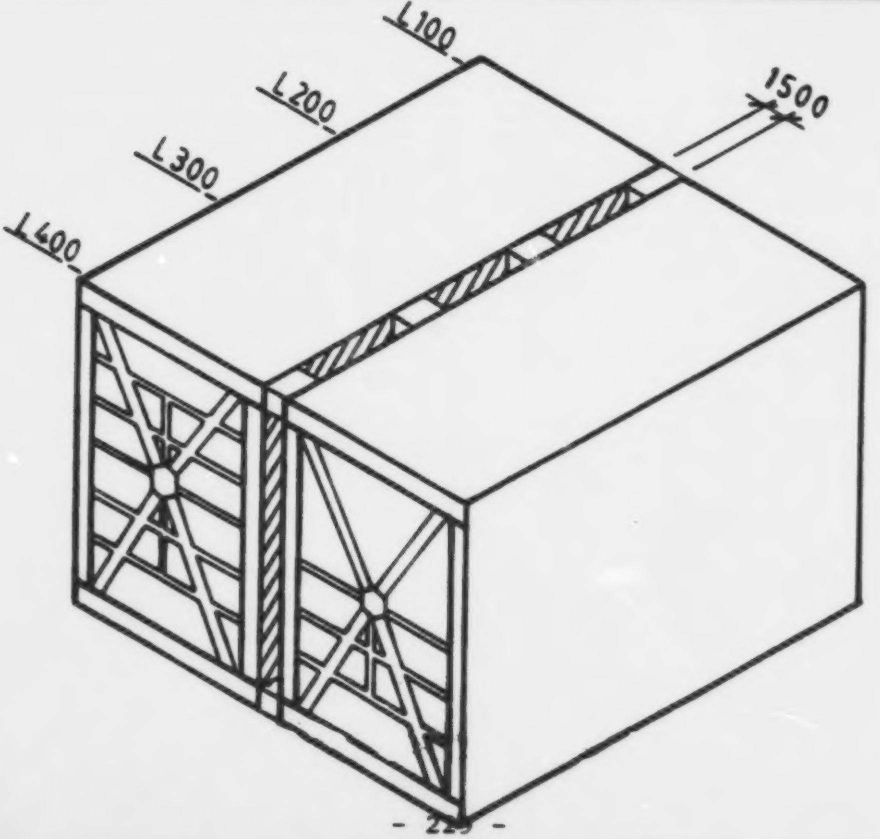
- REDUCE OVERALL WEIGHT BY DEVELOPING STRUCTURAL SYSTEMS WITH MULTIPLE FUNCTIONS RATHER THAN DESIGNING SEPARATE SYSTEMS FOR EACH FUNCTION

HIBERNIA TOPSIDES CONCEPTUAL STUDY

STRUCTURAL DESIGN CONCEPT

- INTEGRATION OF GLOBAL SUPPORT SYSTEM IN MODULE STEEL
- MODULE STRENGTH & STIFFNESS SYSTEMS COMBINED INTO SINGLE INTEGRATED STRUCTURE
- INTEGRATION OF BLAST WALLS AND TOPSIDE TANKAGE INTO THE MAIN LOAD CARRYING SYSTEMS
- OMITTING MODULE LIFT AS A LOADCASE


L 100
L 200
L 300
L 400


L 100
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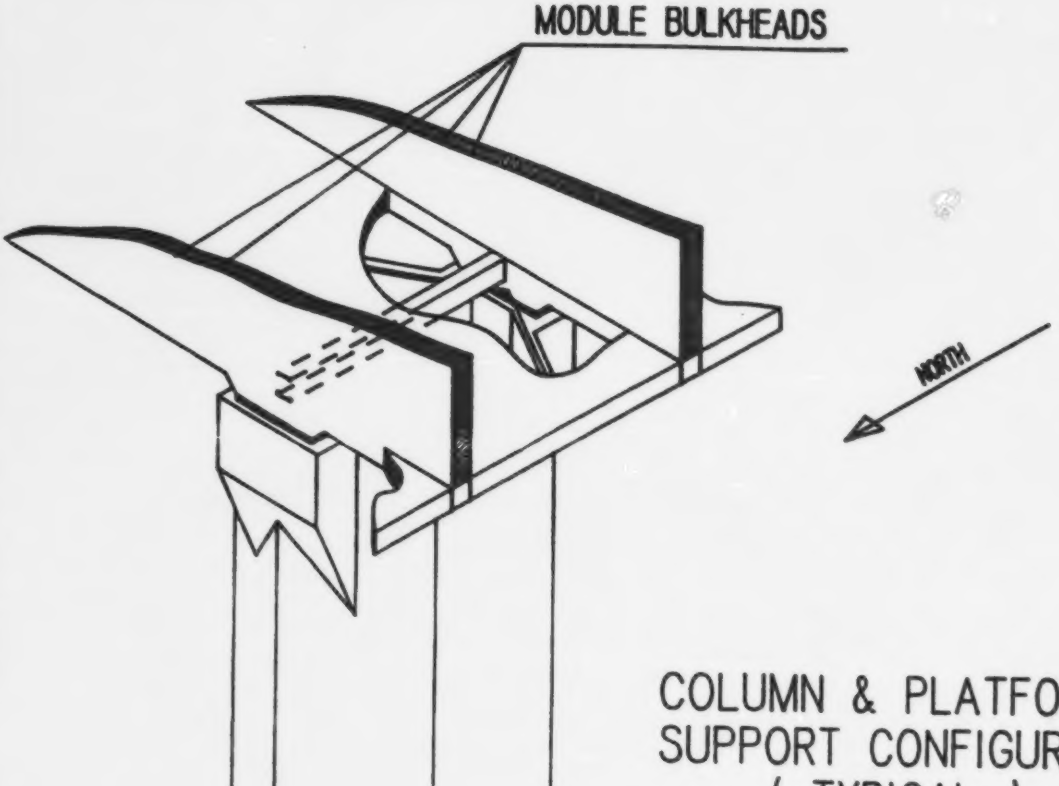
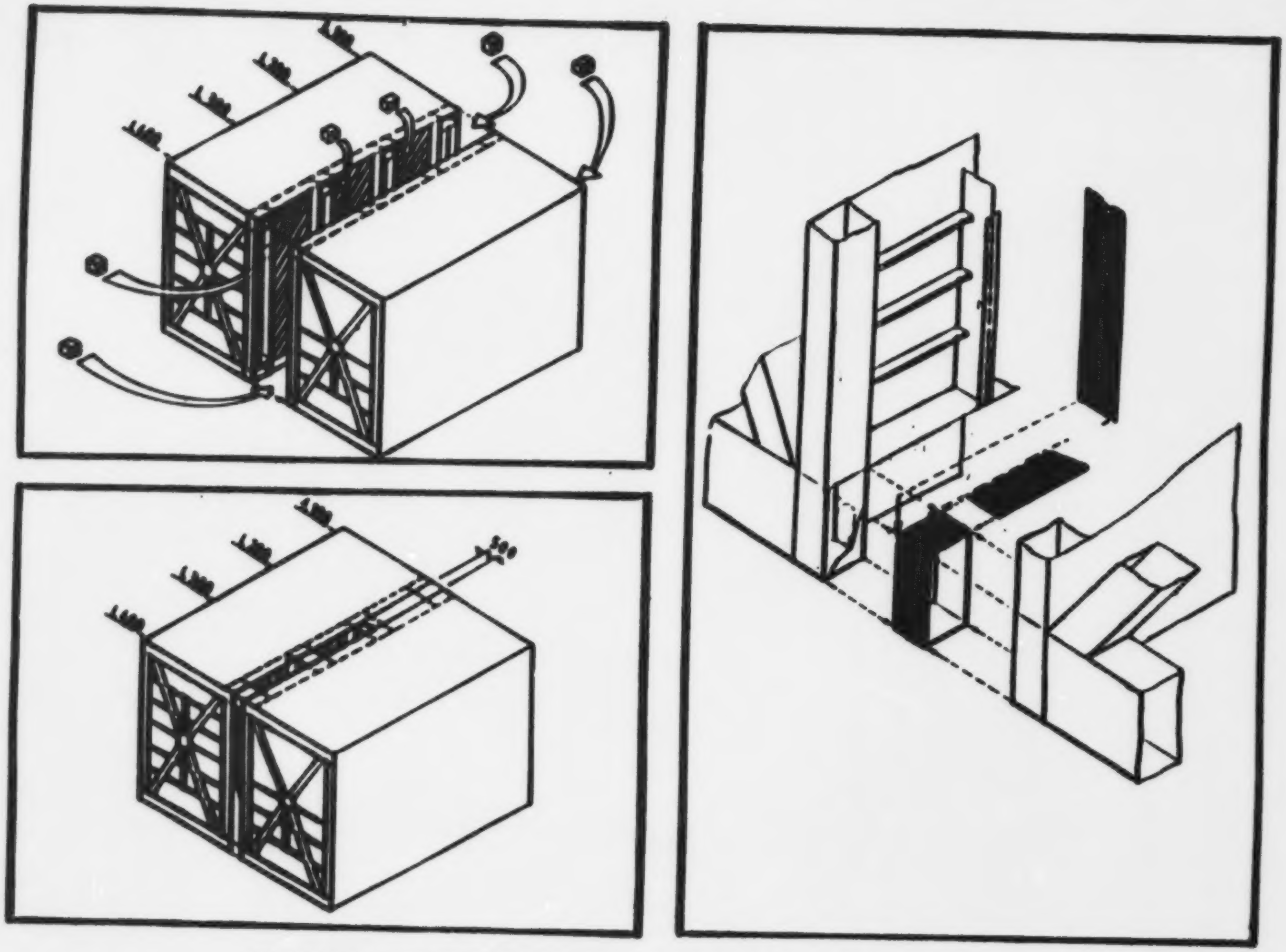
L 300
L 400
1500

HIBERNIA TOPSIDES CONCEPTUAL STUDY

GBS/TOPSIDES INTERFACE


MODULE BULKHEADS
NORTH

COLUMN & PLATFORM
SUPPORT CONFIGURATION
(TYPICAL)



DOUBLE BULKHEAD MODULE INTERFACE

HIBERNIA TOPSIDES CONCEPTUAL STUDY

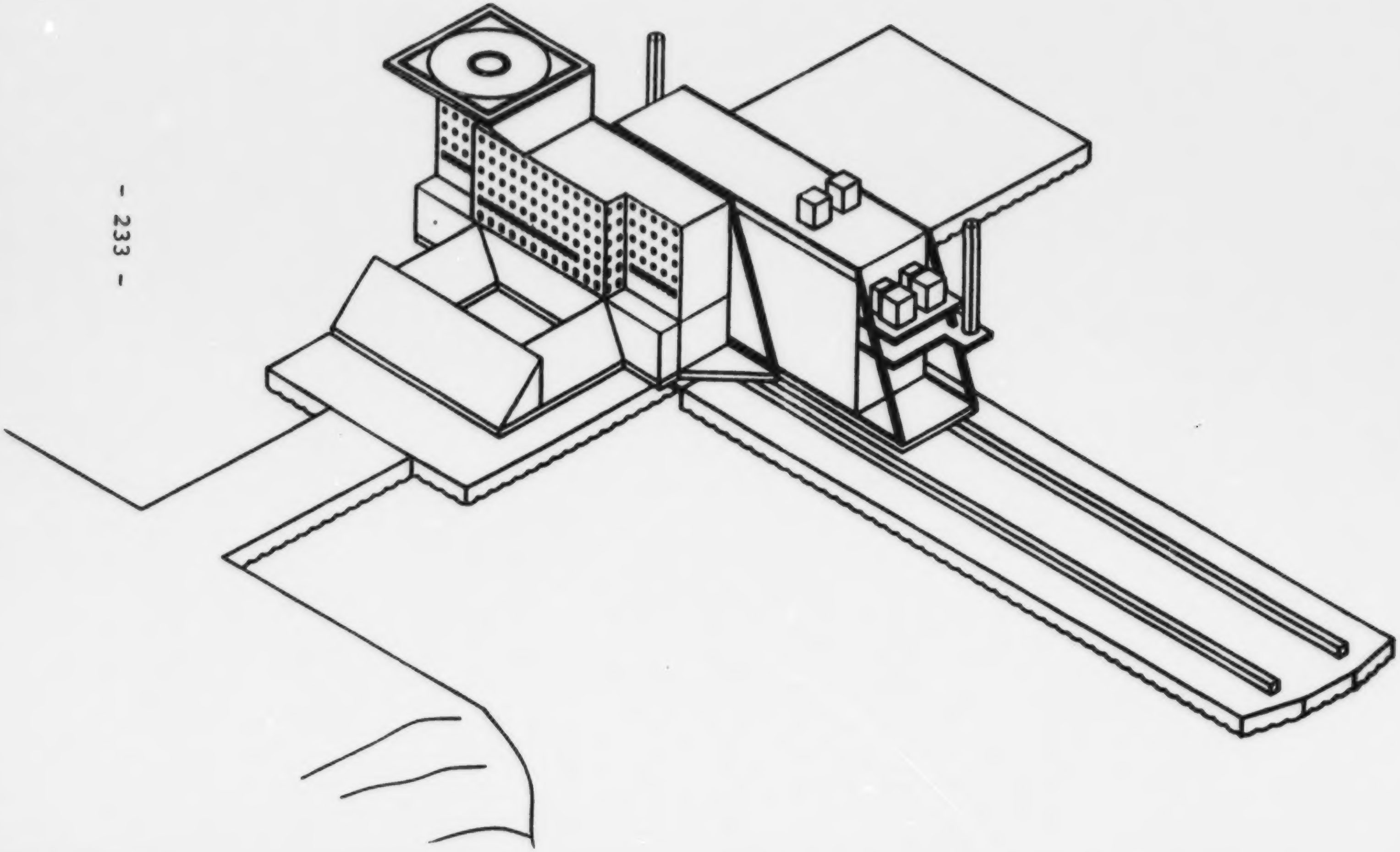
MODULE LOAD ON/OFF

OPTIONS:

- MULTI WHEEL TRAILERS(MAMMOET)
- SKID SHOES AND HYDRAULIC PUSH PULL CYLINDERS
- SKID BEAMS AND PULLING WINCHES

HIBERNIA TOPSIDES CONCEPTUAL STUDY

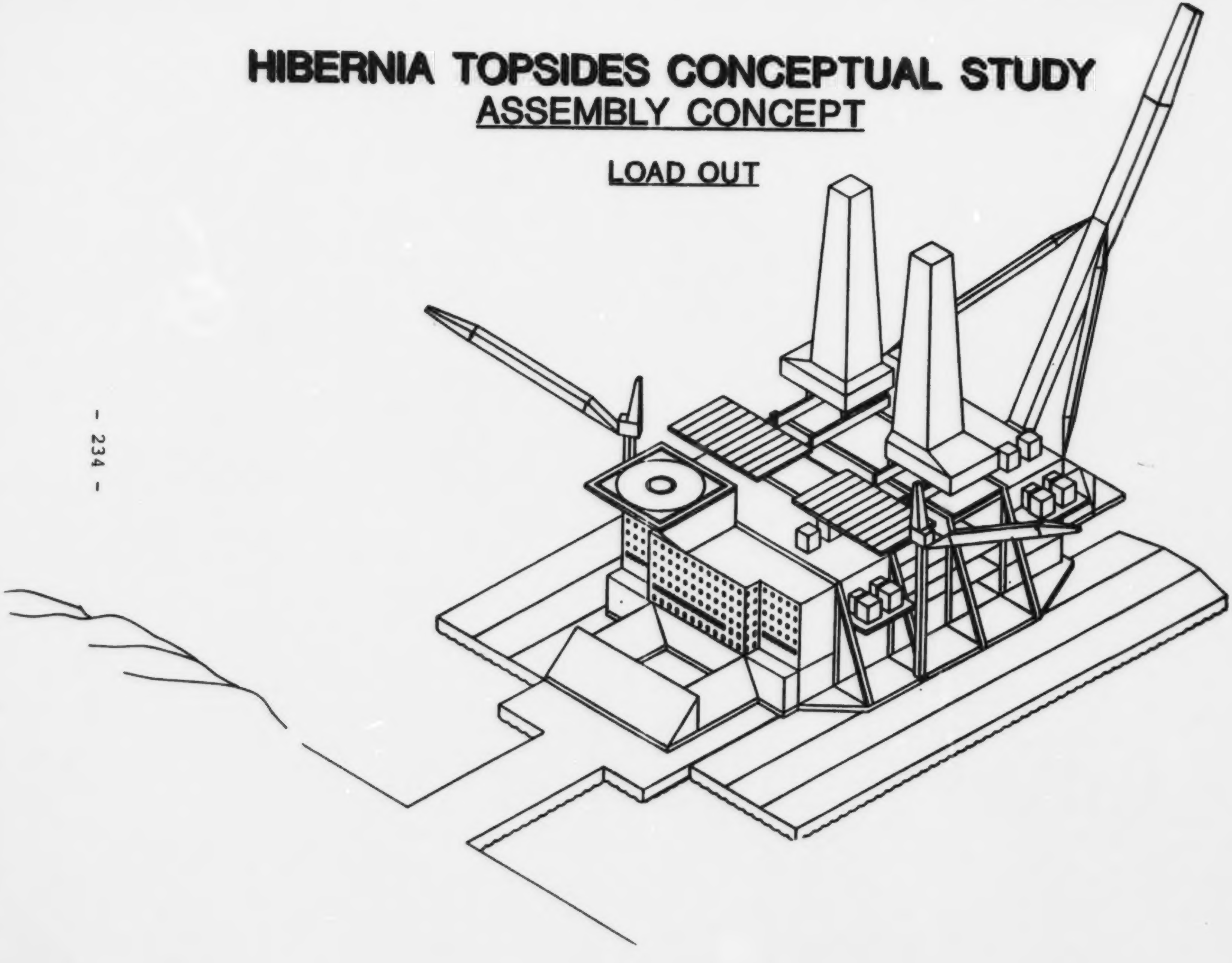
ASSEMBLY CONCEPT



HIBERNIA TOPSIDES CONCEPTUAL STUDY

ASSEMBLY CONCEPT

LOAD OUT



3. PLATFORM ARRANGEMENT

The development of the topside layout has been carried out based on the concept of 5 large main modules as determined during Phase A studies.

The principle arrangement of equipment in different modules as developed in Phase A has been retained.

Generally, the layout has been developed by routing the major piping system to prove space allocations, and analysing the layout for ease of operation and maintenance. When reviewing the material handling requirements on the proposed topside, it was concluded that the crane located at the process module was not necessary.

Due to the width of the drilling module being reduced, it proved necessary to arrange additional space on top of the module in order to accommodate the offices and storage space required for drilling.

Also, the mud cleaning system was arranged on the BOP deck in the Wellhead Module.

Due to the overall layout principle of the platform, it was necessary to arrange the drilling functions distributed vertically. Communication between the different decks is established by stairs, but if later operation studies determine a need for frequent personnel relocation during the drilling operations, installation of elevators should be considered.

Considerable effort was expended on developing the flowline and well manifold piping arrangement. A feasible arrangement is proposed whicn allows choice of routing between any manifold & any wellhead.

In all areas on the topside, space has been reserved to ensure that all equipment items requiring maintenance can be transported out to a laydown area at the platform perimeter, where it can be picked up by one of the two cranes.

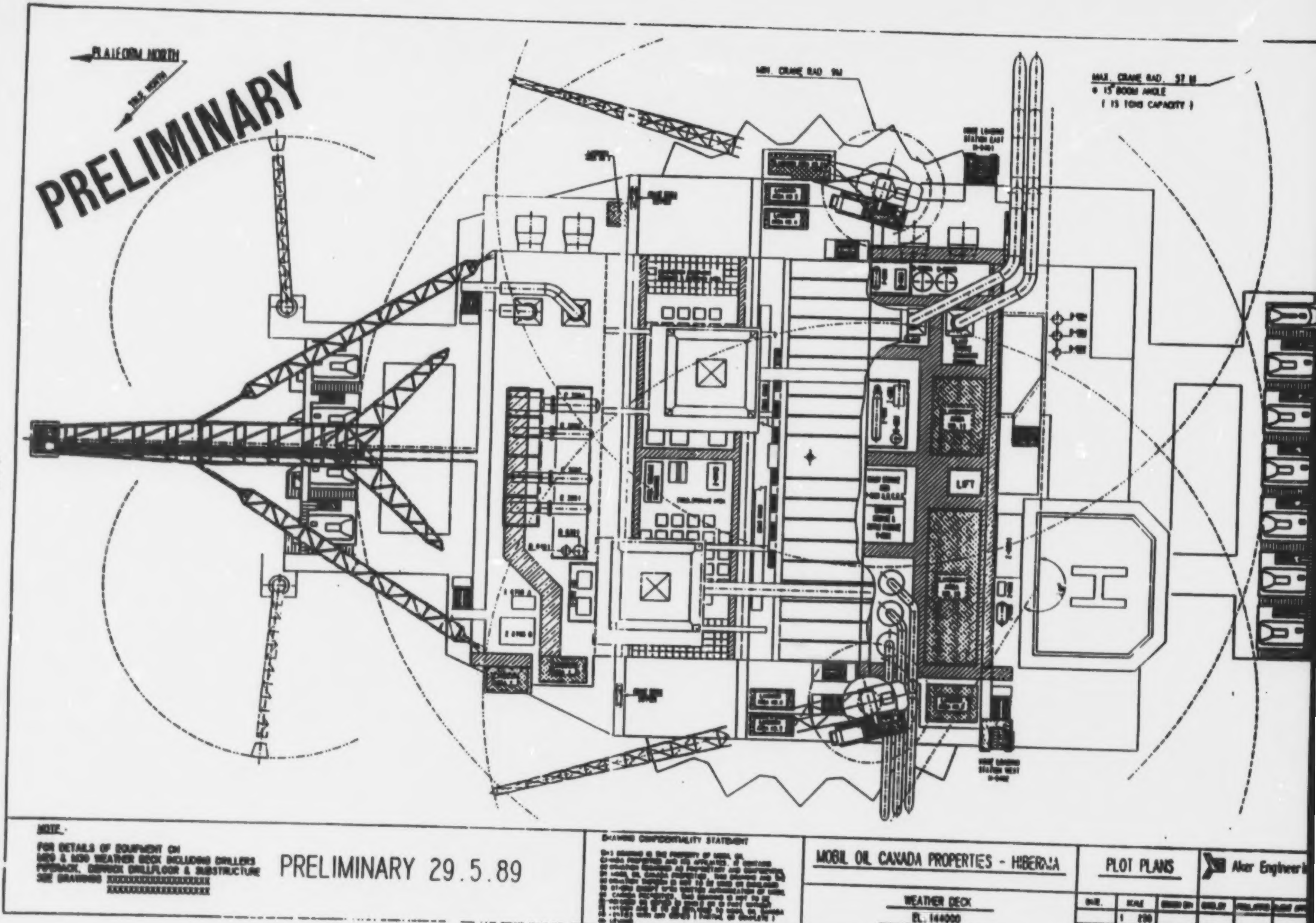
During the layout work, every effort was made to integrate the plant arrangement with the GBS requirements. Some small modification with regard to material handling and access location have been made but it is expected that these can be assimilated.

Discussion with regard to J tubes and risers location has been effected during the study but the layouts reflect the information supplied with the Base Case.

HVAC on the platform is based on natural ventilation in the hazardous areas and decentralized plant rooms for the shafts and closed areas within the modules.

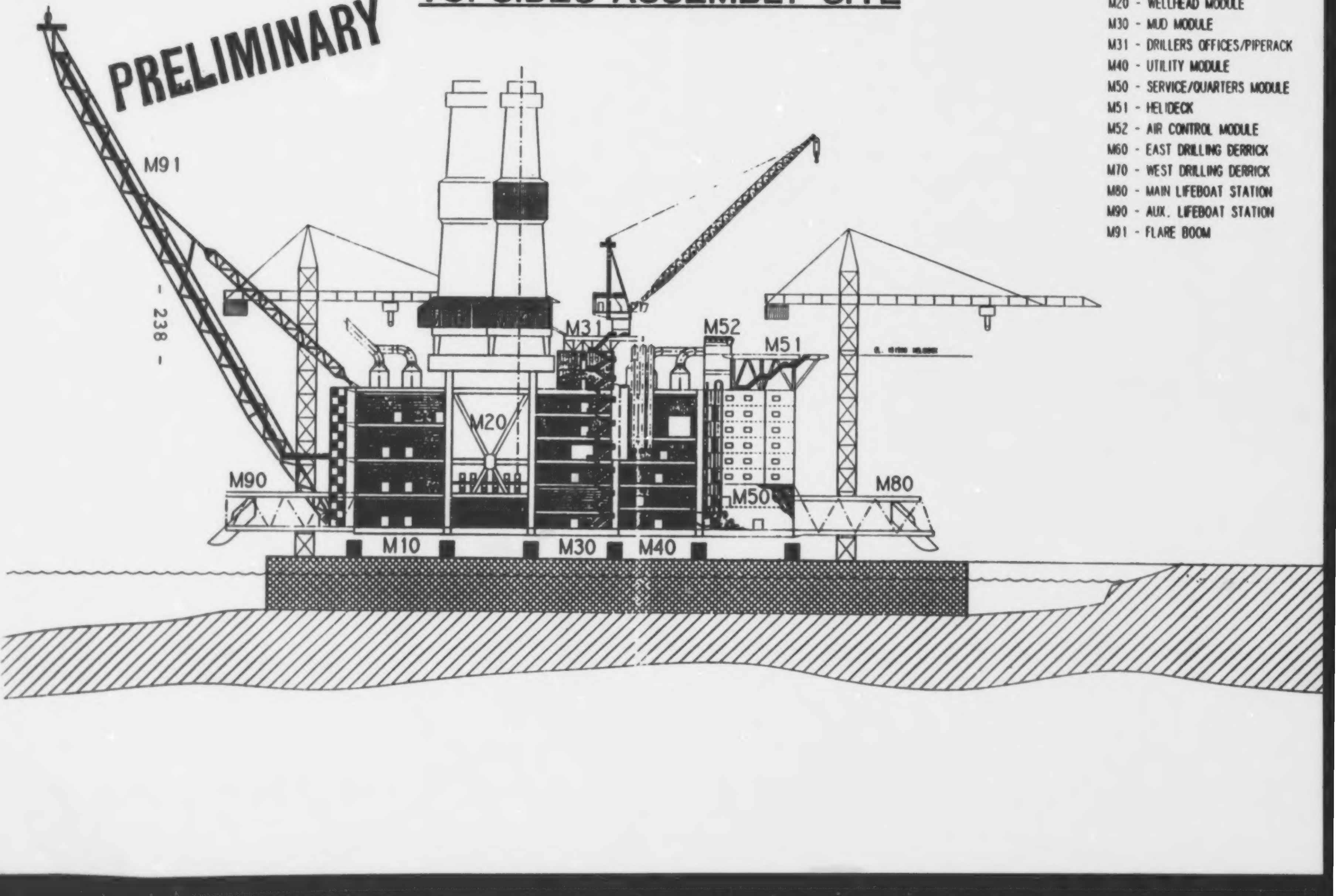
Time did not allow full optimization of all the utility areas in M40 and M50, but the layout is considered practical and the volume allowed is adequate.

Further study is suggested regarding the bulkhead tanks arrangement and the piping philosophy. Some benefits are foreseen in running the piping to and from the tankage within the bulkheads, to avoid complex routings within the modules.

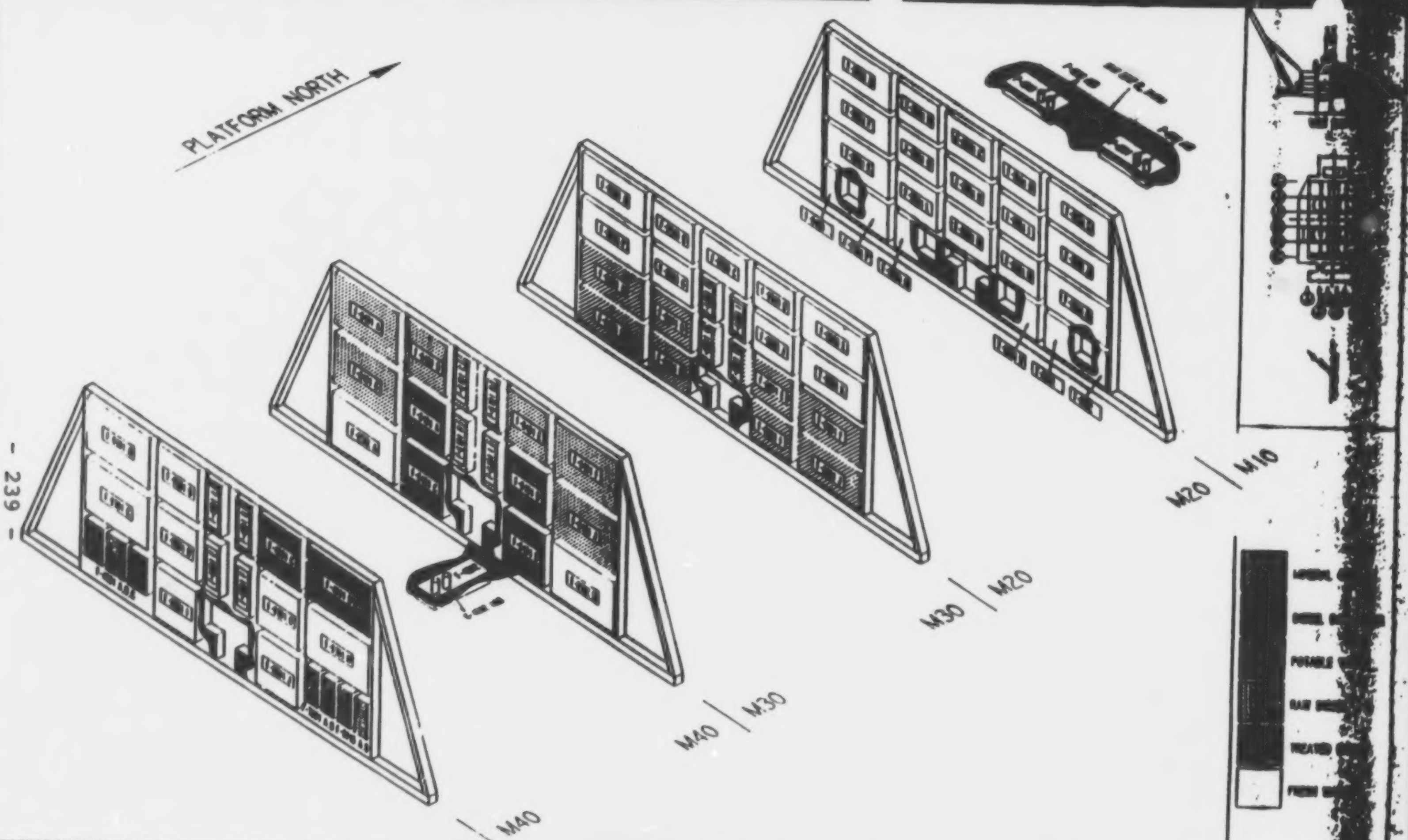

PLATFORM NORTH
TRUE NORTH
PRELIMINARY
MIN. CRANE RAD. 9M
MAX. CRANE RAD. 57 M
@ 15° BOOM ANGLE
(15 TONS CAPACITY)
LIFT
H
NOTE -
FOR DETAILS OF EQUIPMENT ON
MPD & MDD WEATHER DECK INCLUDING DRILLERS
PIPERACK, DERRICK DRILLFLOOR & SUBSTRUCTURE
SEE DRAWINGS XXXXXXXXXXXXXXXXXXXX
XXXXXXXXXXXXXXXXXXXX
PRELIMINARY 29.5.89
DRAWING CONFIDENTIALITY STATEMENT
MOBIL OIL CANADA PROPERTIES - HIBERNIA
WEATHER DECK
EL. 144000
PLOT PLANS
SCALE
1 : 200
Aker Engineeri

HIBERNIA TOPSIDES CONCEPTUAL STUDY

TOPSIDES ASSEMBLY SITE


PRELIMINARY
M91
M90
M10
M20
M30
M31
M40
M52
M51
M50
M80

M10 - PROCESS MODULE
M20 - WELLHEAD MODULE
M30 - MUD MODULE
M31 - DRILLERS OFFICES/PIPERACK
M40 - UTILITY MODULE
M50 - SERVICE/QUARTERS MODULE
M51 - HELIDECK
M52 - AIR CONTROL MODULE
M60 - EAST DRILLING DERRICK
M70 - WEST DRILLING DERRICK
M80 - MAIN LIFEBOAT STATION
M90 - AUX. LIFEBOAT STATION
M91 - FLARE BOOM


PLATFORM NORTH
M50 / M40
M40 / M30
M30 / M20
M20 / M10
POTABLE
RAW
TREATED
FRESH

MOBIL OIL CANADA PROPERTIES - HIBERNIA

BULKHEAD TANKAGE ARRANGEMENT

HIBERNIA TOPSIDES CONCEPTUAL STUDY

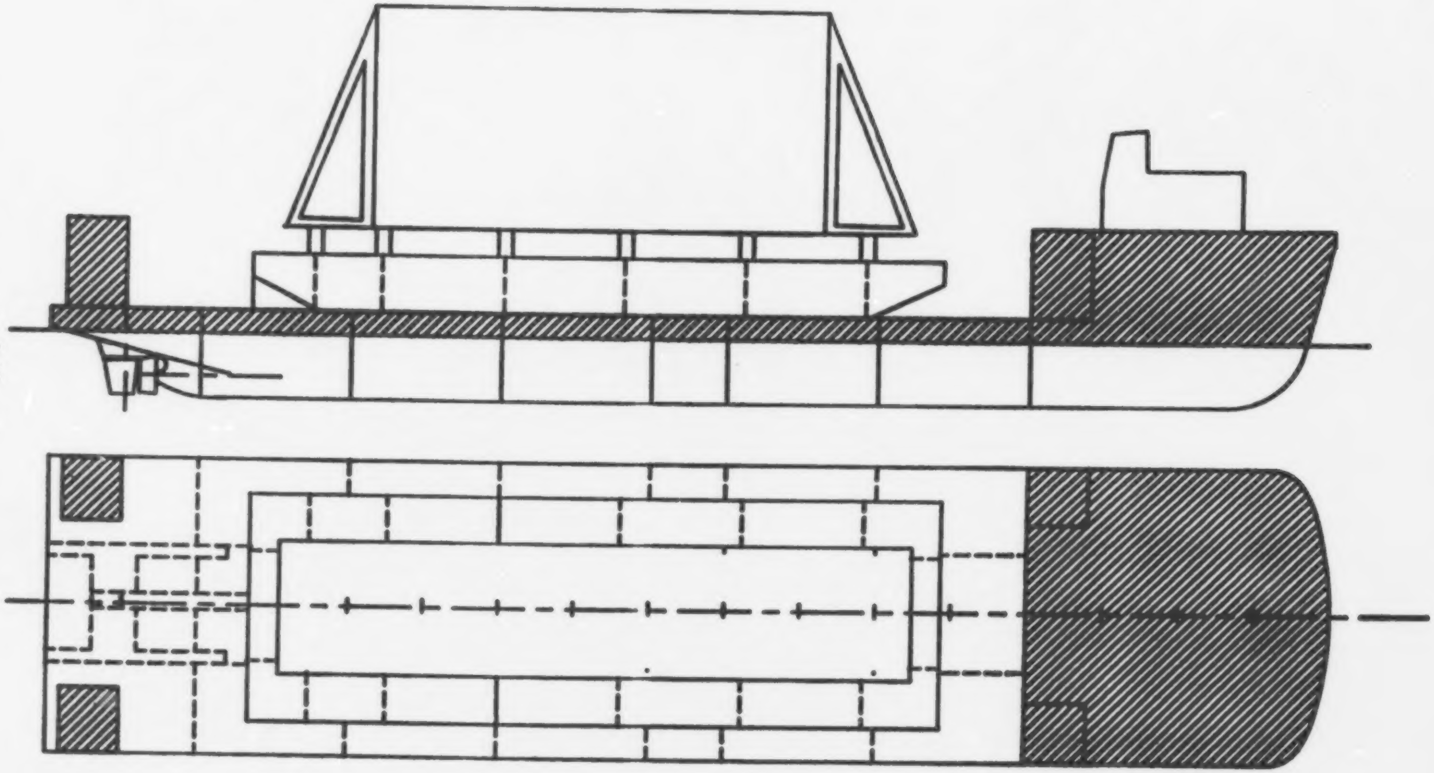
MODULE TRANSPORTATION

OPTIONS:

- MODULE ON TOWED BARGE
- MODULE ON HEAVY LIFT VESSEL(MIGHTY SERVANT TYPE)
- MODULE/BARGE ON HEAVY LIFT VESSEL

HIBERNIA TOPSIDES CONCEPTUAL STUDY

MODULE TRANSPORTATION



HIBERNIA TOPSIDES CONCEPTUAL STUDY

SAFETY EVALUATION

ACCIDENTAL EVENTS:

- FIRE AND EXPLOSION IN PROCESS AREAS
- BLOWOUT IN WELLHEAD AREA
- GAS LEAKAGE IN RISER SHAFT
- HELICOPTER COLLISION ON LQ

CATASTROPHIC EVENT:

- LOSS OF WELLHEAD AND PROCESS MODULES

HIBERNIA TOPSIDES CONCEPTUAL STUDY

SAFETY EVALUATION

RESULTS

- HIGH SAFETY LEVEL AS A RESULT OF SEGREGATION OF PROCESS MODULE AND LQ
- MODULE BULKHEADS PROVIDE IMPROVED FIRE AND EXPLOSION PROTECTION
- 2 CONTINUOUS ESCAPE ROUTES AT 2 LEVELS ARE PROVIDED
- ALL HC AREAS ARE NATURALLY VENTILATED
- ROUTING OF HC LINES IN RISER SHAFT SHOULD BE REEVALUATED

HIBERNIA TOPSIDES CONCEPTUAL STUDY

TOPSIDES WEIGHT

	HIBERNIA BASE CASE	HIBERNIA 1989
MAIN SUPPORT FRAME	8,280	-
CELLAR DECK OUTFITTING	8,230	-
PROCESS/UTILITY/WELLHEAD	13,960	17,750
ACCOMODATION MODULE	3,120	5,740••
DRILLING FACILITIES	8,675	8,548
FLAREBOOM	460	262
SUB-TOTAL	42,725	32,300•
TEMPORARY WEIGHT FOR TOW	2,000	2,000
TOTAL TOW-OUT WEIGHT	44,725	34,300

• DOES NOT INCLUDE 3rd CRANE(~500 TONNES)

•• INCLUDES TWO BOTTOM LEVELS OF OFFICES AND UTILITIES

HIBERNIA TOPSIDES CONCEPTUAL STUDY

SUMMARY AND CONCLUSIONS

1- APPROXIMATELY 10,000 TONNES WEIGHT REDUCTION

2- IMPROVED SAFETY

3- IMPROVED LAYOUT EFFICENCY

4- REDUCTION IN RESUPPLY FREQUENCY

5- IMPROVED FABRICATION EFFICENCY

6- REDUCTION IN ASSEMBLY SITE REQUIREMENTS

SPEAKER : FRODE JENSEN

COMPANY : NORTH ATLANTIC CONTRACTORS

LOCATION: CANADA

TOPIC : COST EFFECTIVE CONCRETE FLOATERS

BIOGRAPHY: Frode Jensen has an M.Sc. in Naval Architecture and Marine Engineering from the Norwegian Institute of Technology (1984). He has worked for Norwegian Contractors a.s., and has been a member of NAC, since 1985.

Mr. Jensen has actively participated in the development of NAC's concrete floaters such as; analyses, discipline leader and project manager. He is presently manager of the analysis group at NC.

ABSTRACT

"COST EFFECTIVE CONCRETE FLOATERS"

The paper will describe two types of concrete floaters; the semisubmersible platform, and the concrete spar buoy. Both are suitable for drilling and production, and both structures may provide oil storage. The buoy may alternatively serve as a smaller structure to be used for offloading purposes only. The semisubmersible will be suitable for exploration purposes also.

The concrete semi can be shaped almost identical to traditional steel semis, but offers several advantages such as; insensitivity to increased topside weights, lower cost, shorter schedule and structural simplicity. Further the concrete hull can be considered virtually free of time consuming inspection, maintenance and repair. The hull durability, strength and robustness against all kinds of deterioration (corrosion,fatigue, fire, impact etc.) improves operational efficiency and cost effectiveness. If required, the concrete semi can accomodate oil storage.

The concrete spar buoy has a shape similar to a bottle and offers motion characteristics similar to conventional semisubmersibles. The spar buoy is catenary anchored and is recommended for subsea wells with flexible risers.

The structural layout of this floater is simple, and it basically consist of an inner and outer concrete cylinder. Typical outer column diameter ranges from 20 to 40 m, and depends on topside load, storage capacity requirement and waterdepth.

The spar buoys are generally designed with drafts ranging from 60 to 200 m depending on actual waterdepth on the site. For waterdepths more than 250-300 m, the floater may be designed for topside loads up to 25.000 tons.

Crude oil storage up to 700.000 bbls can be accomodated in the lower hull. In smaller waterdepths the capacity will be lower.

Both technical and economical aspects will be focused on in the paper. This will include design, construction, operational performance and cost and schedule.

COST EFFECTIVE CONCRETE FLOATERS

Authors: Ragnvald Børresen
Christian Nygaard
Frode Jensen

INTRODUCTION

North Atlantic Contractor's (NAC) experience with concrete structures goes back to 1973 when the first concrete gravity base structure was built and installed in the North Sea. Since then 11 concrete CONDEEP platforms have been designed, built and installed and a vast amount of experience has been accummulated. The growing interest over the years for concrete structures has also lead to the development of concrete floaters.

Fig. 1 shows the recent concrete floaters developed by NAC.

The first concrete floater designs developed by NAC were in 1975, but it is during the past five years that a world wide recognition of the concrete floaters, as a cost competitive alternative to steel floaters, has emerged. One of the major breakthroughs for concrete floaters was the decision made by Conoco and their partners in 1987 to select a concrete Tension Leg Platform (TLP) for the Heidrun field in the North Sea.

The present paper describes the main features of a:

i: Concrete Semisubmersible catenary anchored platform suitable as a PDQ with oil storage using flexible risers.

ii: Concrete Spar Buoy suitable for drilling/production with large crude oil storage, or as a small offloading buoy.

The Concrete Semi has been subjected to extensive design and development work. The floater is considered promising, and the concept is believed to be a highly competitive alternative for drilling, production and oil storage applications.

The Concrete Spar Buoy hull has been designed and developed by NAC, while different companies have contributed to the development of deck and topsides. The Spar concept is considered to be a competitive, cost efficient alternative for otherwise marginal field developments.

PLATFORM DESCRIPTION

The Concrete Semisubmersible may have 4 or 6 circular columns depending on the choice of deck/topside layout. The columns are interconnected by pontoons with a rectangular cross section. The overall shape of the floater will be almost identical to a steel semi - the difference normally being a larger draft and slightly larger column diameter. See Table 1 for typical key figures,and Figs.2 and 3.

The hull is designed according to the current draft guidelines by NPD. The columns consist of a circular shaped cylinder throughout its lenght except at top where they may be flared to give optimal deck/column support conditions. A typical arrangement for support of the deck structure on to the top of the columns are shown in Fig.4. The columns have an annulus compartment around the still water line for additional safety in case of ship or ice impact. The pontoons may be subdivided with vertical walls in both transverse and longitudinal directions.

If case of a semisubmersible with oil storage, the columns will be the only buoyancy members. The crude oil is stored on a "water pillow" in the pontoon, and there will be a buffer cell that prevents crude from being pumped directly to sea. There is no mechanical equipment in the pontoons, and no access is therefore considered neccesary.

The Concrete Spar Buoy is applicable both as a small offloading buoy or as a PDQ platform with crude oil storage capacity of up to 700.000 bbls. Depending on the waterdepth the platform can carry up to 25.000 t topside weight (above top of columns), and has drafts ranging from 60 m to 200 m. The Spar Buoy is traditionally catenary anchored - normally by 8-10 anchor lines. See typical key figures in Table 2.

The hull has a vertical cylindrical body with a smaller diameter neck penetrating the waterline. The difference in column diameter between the upper and lower parts provide motional advantages. To improve stability during the temporary phases, the lower part of the body is tapered to a smaller diameter bottom slab. The Spar Buoys with largest drafts have constant outer diameter throughout their length.

Two typical hull geometries are shown in Figs.5 and 6. The main difference between the two is that the small draft version has drilling and workover capabilities. It follows that the internal tank arrangement is slightly different between the two. Both alternatives are described below.

The oil storage will be an open system, meaning that the crude oil will be resting on a water cushion which is open to sea. When there is no oil in the storage, it will be filled with seawater. See Fig.7.

The outer ring compartments above the storage are water ballast tanks. Use of these tanks will ensure that a constant draft is being kept during loading or offloading the storage. This is necessary due to the difference between oil and seawater density, see Fig.7. In the small draft version there are ballast water tanks located at the bottom slab level which are also used for constant draft control. Storage of liquid, such as diesel, fresh water etc. are located in the compartments next to the trim water compartments.

Solid ballast will be located in the outer annular compartments in the tapered part of the lower body.

If drilling and workover capabilities are required, there will be an open cylinder or moonpool, located in the centre axis of the platform as shown in Fig.6.

Structural simplicity is a common design feature for all concrete floaters. The concrete hull can withstand ambient water pressures without the complex assembly of webs, stiffeners or girders used in a steel hull. Compared to gravity-based structures, the floaters represent a downscaling in both size, complexity and stress levels. Several load conditions both for temporary and operating phases have been considered. The design calculations show that the required amounts of concrete and reinforcement (ordinary and prestressed) are moderate and all relevant loads can therefore be easily designed for.

MOTION RESPONSE

Concrete floaters have generally motion response amplitudes comparable to similar steel floaters. Typical results for a concrete semi with a topside weight of 15.000 t are shown in Table 3. The values are most probable largest amplitudes during a 6 hours storm representing a 100 year condition. Spectral peak period is 18.0 s and significant wave height is 15.4 m. In Fig. 8 the corresponding motion transfer functions are shown.

The motion response characteristics for the Spar Buoy are comparable to conventional semisubmersibles. The geometrical shape and the motion characteristics favour use of flexible risers with subsea wells.

Several parametric studies have been carried out in order to reduce motion responses. Work is still in progress to find the optimum hull shape. The characteristic shape of the floater with a smaller diameter column penetrating the waterline and a larger column diameter of the main body ensures counteracting water pressures on the "shoulders" and the buoy base. Their areas can be tuned to achieve cancellation in heave for desired wave periods. See the transfer functions in Fig.9.

The Spar Buoy will be subjected to second order motions, which are significant and must be allowed for when the total motion response amplitudes are calculated. The total estimated response amplitudes, where second order motions are included, are based on on model tests carried out on a similar platform. See typical response amplitudes for a floater in Table 4. Motion response amplitudes for a typical semisubmersible floater are shown in the same table for comparison. The floater has the following characteristics:

- Topside weight : 5.000 t
- Oil storage : 330.000 bbls
- Draft : 110 m
- Water depth : 150 m

ANCHORING

The catenary anchored semisubmersible will normally require an 8 to 12 line system depending on hull size and site conditions. On the Grand Banks off Newfoundland the environmental forces on the vessel will be large whilst the waterdepth is relatively small.The anchor lines will in most cases consist of a combination of wire and chain with traditional fairleads mounted onto the columns.

Due to the difference in hull weight between steel and concrete, the latter will have roughly a 15-20% larger displacement. However, the environmental loads (such as wave drift and current loads) acting on the platform, which are to be counteracted by the anchoring system will only be about 5% larger than for steel floaters. The wind load is the dominating static load and will be more or less identical for the two floaters. The difference in anchor line size and thereby also cost of the anchoring system between a steel and a concrete hull is therefore small for shallow water and negligible for deeper water.

Table 5 shows some key data of an anchoring system for both 95m and 350m water depth in extreme conditions. The floater has a topside load of 15.000 t and a displacement of 45.100 t. The analysis is based on the DnV rules 1989.

The Spar Buoy will also be catenary anchored and the design is based on current NPD draft guidelines on mooring systems for floating production platforms. A catenary anchored platform is attractive since relocation for use at other fields can be performed at moderate costs.

The anchoring system will normally consist of 8-10 mooring lines symmetrically spread around the platform. Taking into consideration that space for the flexible risers can be required on both sides of the platform, the anchor lines are grouped in pairs as shown in Fig.10. Each anchor line consist typically of a combination of chain and wire or chain only. Such size anchorlines and wires are frequently used for mooring of conventional semisubmersibles. The line length from the anchor to the fairlead varies with waterdepth, but is typically 1200 - 2000 m. The design can be either active or passive. Table 6 gives some key information on a typical anchoring system.

FLOATING STABILITY

Stability calculations have documented adequate stability for the semisubmersible during all relevant phases.

Due to the nature of the concrete material, as opposed to steel, it is not possible to deballast the hull to a transit draft where top of the pontoon is above the waterline as commonly known for existing steel semisubmersibles. If a transit draft is required, an additional displacement of approximately 25-30% must be added. Designs where this has been a requirement have shown that the cost implications are marginal.

The stability of the floater shown in Fig. 11 complies with the requirements of Det norske Veritas (DnV) in all relevant conditions. DnV treats concrete floaters slightly differently to steel floaters, and they basically states that "provided that there are no penetrations to sea and that the concrete wall is 0.30 m or thicker, no watertight subdivision is required." The reason for this is the low probability of damage through a concrete wall of such a thickness.

The semisubmersible floater has watertight subdivision in the damage zone of the columns (5 m above and 3 m below the still waterline). Further, as an additional barrier, as compared to the DnV requirements, the pontoon has also watertight subdivision to handle damage conditions such as e.g. dropped objects. The latter is only relevant in the case of no oil storage. In case of crude oil storage, the columns are the only buoyancy members. The pontoon top will be covered by 0.5 m light weight aggregate concrete (density 1.0 t/m^3) to withstand potential dropped objects. It should be noted that the complete pontoon will be oil and/or waterfilled at all times and hence a potential damage to the pontoon will not create a stability problem.

Stability calculations have documented adequate stability for the Spar Buoy during all relevant phases. The floater fullfills the requirements of DnV.

HULL OUTFITTING AND OIL STORAGE

The semisubmersible with oil storage is separated in a safe area below the quarter and a classified area below the process side. The mechanical outfitting of the hull can be divided in two categories:

- Hull related equipment
- Topside related equipment

The hull related systems are designed to perform operations necessary for construction and operation of the floater. The trim system consists of deballasting and ballasting pumps and is designed to control tilt and draft and to actively compensate for weight changes during filling and offloading of oil to/from the storage. All water in and out of the structure is pumped over the top of the column, and there are no pipe penetrations in the columns.

The topside related equipment will be located in top of the columns. All column penetrations to sea take place within the annulus below the waterline. Any collapse of piping or equipment, system malfunction or maloperation can therefore only result in flooding of the annulus.

All seawater pumps are casing mounted within the annulus, with individual intakes piped external to the column down to a given elevation. All pumps are pulled and serviced from the main deck. The topside related systems are:

- fire water system
- sea water system
- disposal system
- crude oil storage system

The floater utilizes only the columns for buoyancy, and can therefore use the pontoons for crude oil storage,see Fig.12. The crude oil is stored on a water cushion which is open to sea. The storage has a contingency volume of water which shall prevent production of oil to sea. During production to storage, water is displaced from the storage compartment through a buffer cell out to sea. Sea water flows freely into the storage during crude oil offloading to the tanker. The buffer cell acts as a crude oil trap. Due to the different density of oil and water, the floater will change weight during loading and offloading. To keep constant draft and tilt, weight change must be compensated for by adding or removing trim water.

The crude oil system is designed to receive crude oil at a production rate and distribute it to the storage compartments. The ballast water buffer cell is normally designed to contain 10-11 hours peak production. In addition to this water buffer cell, there will be an extra water layer in the pontoons due to height of strainer at inlet, sludge and tolerances for instruments and alarm ranges. Totally 3 m on the pontoon height is normally not included in the net storage volume.

The crude oil pumps will be submerged vertical pumps mounted in a caisson extended down from main deck into the annulus inside the column. Separate suction lines from each pump casing are routed externally embedded on the column down to the four storage volumes. Offloading is assumed from three compartments at the same time. The stiffening walls inside the pontoons are made as ribs or open bulkheads with penetrations to make oil and water flow freely.

Sampling of ballast water should be provided for at the outlet. However, Nort Sea experience has proven the ballst water discharged to be far cleaner (1-3 ppm) than required by the authorities.

The hull outfitting and oil storage system of the Spar Buoy is based on the same principles as for the concrete semisubmersibles, see Fig.13.

RISERS

The flexible risers can be mounted on a balcony at the aft end of the deck/topsides of the semi, and arranged in a lazy wave configuration as shown in Fig.14. An alternative location would be to mount the riser connectors at the pontoon with hard pipes from the pontoon (along the columns) to the topsides. In this way the risers will be less exposed to waves, possible impact such as boats and ice etc. It is also possible to attach the connectors on a steel support frame inbetween the two aft columns and some 10-15 m below the waterline. The hull (only when the crude tanks are full) can then be deballasted to achieve dry access to the connectors for maintenance purposes.

The Spar Buoy can support a range of flexible riser tie-in alternatives such as risers suspended from the deck, connected to the main body with hard piping to the deck, and flexibles pulled in through pulltubes. Flexible lines and pulltubes are considered best suited for most applications. These offer simple operation, installation and maintenance, but at some increased cost and weight. The last alternative is shown in Fig.15 together with an UKOLS offloading system. The flexible production risers can be steep or lazy wave depending on whether they serve wells below the platform, or sattelite wells. Each flexible is pulled in through a pull tube running through the hull structure from well below the waterline and up to the production deck.

HULL CONSTRUCTION

More than ten concrete Gravity Base Structures (GBS) have been designed, built and installed by NC, a member of NAC, over the past 16 years. The construction of both the semisubmersible and the Spar Buoy will be carried out based on the same techniques and methods known from the construction of the previous GBS's.

The construction of the Concrete Semisubmersible can be completed (without the deck) in dry docks with depths ranging from 5 to 8 m, whereas the semisubmersible with oil storage will require a deeper dock. However, completing the pontoon in a dry dock and performing slipforming of the columns inshore, requires docks of only 3-4 m depth. Hence, purpose-built dry docks - if suitable sites are not present - have proven to be quite attractive. Studies where the lower part of the hull is constructed on 2 or 3 barges welded together, have also been carried out and proven to be feasible. A solution where a complete Semisubmersible without storage, without the deck, is performed in dry dock, is shown in Fig.16. The construction techniques which involve slipforming, provide an efficient and economic way of building such structures.

The simple geometrical and structural layout results in a very short construction time and a favourable project execution flexibility and cash flow. From start in dry dock until completion for deckmating, the construction time for the Concrete Semisubmersible is 8-12 months, whereas it will be 11-13 months for the semisubmersible with storage. Several studies have been performed where possible building of the concrete structure in Newfoundland has been evaluated.

The construction techniques relevant for the Spar Buoy, involve a combination of dry construction on barge and inshore slipforming. This provides an efficient way of building such structures. Alternatively a dry dock can be used for construction of the lower part. The structural layout of the buoy is simple and consists to a large extent of vertical cylindrical sections. This is ideal for slipforming operations allowing a short and economical construction time - only 6-8 months (depending on outfitting requirements).

The lower 20-30 m of the structure can be completed on a barge moored close to a suitable site. See Fig.17. By ballasting the barge, the structure will float off and it can now be towed to a deep water site where slipforming and filling of solid ballast can take place. Then mechanical outfitting will be installed before deck mating or lifting of modules will take place.

ADVANTAGES OF CONCRETE HULL

Concrete has reserve strength against external pressures, so that a draft increase of the structure does not necessarily impose a penalty on the design. This advantage is particularly favourable and is one of the reasons why a concrete semisubmersible can carry larger topside weights and oil storage as opposed to steel semisubmersibles at a competitive overall cost. This is also highly valid for the Spar Buoy which can have drafts down to 200 m or more. Substituting the concrete by steel as construction material for the Spar Buoy is therefore unlikely to be a cost effective alternative.

In the sections below, advantages of concrete hulls in general as compared to steel hulls, are highlighted.

A steel floater hull makes extensive use of thin stiffened plate construction. In most designs the columns are stiffened cylindrical shells, with stiffeners running in both the longitudinal and circumferential directions. The pontoons can have a circular or a rectangular cross sectional shape with transverse stiffeners or web frames, as well as longitudinal stiffeners. In the nodes, or column/pontoon intersections, the structural configuration can be quite complex with multiple member intersections and a large number of compartments of varying sizes. With this type of configuration the design of structural details takes a very important role, given the large number of member intersections, and the need to avoid stress concentrations that can impair fatigue life.

Dimensional control and proper alignment of members is also important, for the same reason as fatigue life, and also because of its impact on failure by instability or buckling. Failure by instability can, in many cases, govern the design, given that the hull components, i.e. the columns and the pontoons, are subjected not only to axial loads and bending moments, but to large external pressures. Thus, increasing the draft of a hull has a strong impact on structural design, since the increased pressure resulting from increased depth normally requires added reinforcement and inreased plate thicknesses. A steel hull requires special protection against accidental boat impact, which can take the form of a stiffened double wall in the vicinity of the waterline.

There is extensive experience in the fabrication of stiffened plated structures, with a long tradition in the area of shipbuilding and semisubmersible construction. However, it can be argued that a floating production system, which cannot be taken easily to a dry dock during its operational life, requires more stringent quality control requirements. As a result, it can be stated that the steel hull of a large topside floater is not always straightforward from a construction point of view, given that the structural configuration is complex, with closely spaced stiffeners and multiple plate intersections that make accessibility and work by welders rather difficult.

The Concrete Semisubmersible can carry large deck/topside weights and studies have shown the concrete hulls are fairly insensitive to increased topside weights. Fig.18 shows concrete volume as a function of topside weights. For example, a 10% increase in topside weight would only be an increase in concrete volume of 3-4%. The fairly moderate increase in concrete volume also results in a moderate cost increase when increasing topside weights. For comparison, the hull weight of a steel semisubmersible is plotted as a function of topside weight. It is interesting to note that for larger topside weights, the amount of steel in tonnes will be fairly close to the amount of concrete in cubic meters for a steel and concrete semi respectively.

A concrete floater uses a design which is considerably simpler than for a comparable steel hull. The columns are constructed by slipforming, leading to smooth walls and essentially uniform thicknesses. The material properties of concrete have been shown to be excellent for the marine environment, and experience has proven that offshore concrete structures with materials and configuration, as currently used, are practically free of maintenance. Fatigue has not been the cause of damage on offshore structures, and ways of designing for an adequate fatigue life are well understood. The low permeability and the self healing properties of concrete surface cracks also ensure that rebar corrosion does not occur.

Chemical and mechanical deterioration associated with freezing and thawing have not been reported for any North Sea concrete structure, and this is largely due to the low permeability of concrete. Experience with North Sea offshore concrete structures has also shown that leakage through plain concrete is not a problem.

Another advantage of concrete is its high resistance to impact loads when the external wall thickness is 0.4 m or more. By increasing the wall thickness and the density of reinforcement it is possible to achieve a high resistance against impact.

Concrete construction is a well known activity with a large experience on the subject of North Sea offshore structure. The yard facilities required are simple, the main considerations being adequate access, space and water depth. The material requirements are that the cement and aggregates must be of high and uniform quality and the mix and batching plant must be tested and proven.

The construction techniques, involving in most cases only a dry dock construction period, provides an extremely efficient way of building such structures. Slipforming makes the construction of vertical sections, such as the columns, very simple and fast, so that an increase in platform draft, and as a result, displacement does not entail significant cost increases.

COST AND SCHEDULE

The concrete semi offers several advantages that makes the concept very cost competitive. Deck weight sensitivity studies have demonstrated that the cost of the concrete hull is fairly insensitive to increased topside weight. In Fig. 19 the cost of a fully equipped hull including anchoring, installed offshore, is plotted as a function of topside weight. See also Fig.20 for cost of semisubmersible with oil storage. For example, a 10% increase in topside weight would only be an increase in overall cost (excluding deck) of 2-3%. Fig.21 shows the cost of an empty hull (only concrete and reinforcement work), constructed in e.g. Newfoundland, as a function of topside load. For comparison, similar cost curves for a steel semisubmersible have been presented on the same graph.

The simple structural layout, applying well known construction techniques, enables a fast construction time. This further results in a cost efficient structure. The hull construction time, from start in dry dock and until ready for deckmating, is 11-13 months depending on size of platform. See Fig.22. From contract award, a 4-5 months period is required for detailed engineering and dock preparations prior to start of hull construction. It is the deck/topsides that will be on the critical line, and the hull construction can in some cases be roughly half the construction time of the deck/topsides. Even though the time to "first oil" is not necessarily reduced with use of a concrete structure, it certainly gives flexibility in the project schedule and possible cash flow gains.

The Spar Buoy offers several advantages that make the concept attractive in comparison to other concepts. The main reason being the simple structural layout which is a considerable simplification as compared to any of the existing CONDEEP platforms or other concrete floaters. Most of the structural elements are vertical, which is ideal for slipforming techniques.

The simple structural layout and application of well known construction techniques enables a fast construction. Slipforming is conducted on a four shift basis. The speed varies between 3-4 m per day, which results in a cost efficient structure. In Fig.23 the hull cost is plotted as a function of topside weight.

The hull construction time - from start in dry dock until ready for deck mating is 6-8 months depending on size of platform, see Fig.24. From contract award, a 3-4 months period is required for detailed engineering and dock/barge preparations prior to start of hull construction. It is the deck/topsides that will be on the critical path and the hull construction can, in some cases, be roughly half the lead time of the deck/topsides. Even though the time to "first oil" is not necessarily reduced with use of a cvoncrete structure, it certainly gives flexibility in the project schedule and possible cash flow gains.

CONCLUSIONS

This paper has presented the main principles and charachteristics for:

i: a Concrete Semisubmersible which is catenary anchored and suitable as a PDQ platform.

ii: Concrete Spar Buoy suitable for drilling/production with large crude oil storage, or as a small offloading buoy.

The paper has considered hull design, motion response, structural design, anchoring system, mechanical systems including oil storage, fabrication, cost and schedule.

Both of the concrete floaters have a simple structural layout and offers advantages mainly in terms of the ability to carry large topside weights, a short construction time and a competitive overall cost.

Concrete as a building material has proven to be ideal for the marine environment, since it is relatively insensitive to fatigue or corrosion, and needs minimum maintenance. The construction period required for concrete structure are short and the associated costs are small when compared with other alternatives. All these positive features of the two Concrete concepts have brought a new dimension to the floater concept and make them an attractive alternative for drilling or production.

ITEMS	DECK/TOPSIDE WEIGHT			
	12.000 t	15.000 t	18.000 t	21.000 t
DECK				
- Size (breadth x length) (m)		72 x 84	77 x 87	82 x 90
- Weight (above top of columns) (t)	12.000	15.000	18.000	21.000
HULL				
- Overall breadth x length (m)		72 x 84	77 x 87	82 x 90
- Draft operation/transit (m)	74	25	24	25
- Static air gap (m)		14	14	14
- Column diameter. corner/mid (m)		14/11	16/9.6	16/9
- Pontoon breadth x depth (m)		17x7	16.5/9	18/9
- Displacement (t)	128.000	45100	52.500	59.800
- GM operation (m)		2.1	2.0	2.5
- Crude storage (bbls)	300.000	-	-	-
MATERIAL QUANTITIES				
- Concrete density (C60) (t/m^3)	2.15	2.15	2.15	2.15
- Concrete volume (m^3)	23.800	11000	11.800	12.900
- Reinforcement (t)	6.500	3400	3.700	3.900
- Prestressing (t)	1.000	40	45	48

Table 1 Typical Key Figures Semisubmersibles

ITEMS	KEY DATA			
Topside weight (t)	5.000	8.000	18.000	21.000
Displacement (t)	99.000	135.000	181.000	223.300
Oil storage (bbls)	330.000	320.000	500.000	700.000
Water depth (m)	150	130	330	330
Draft (m)	110	80	200	220
Column diameter (m)	25/36	28/51	34	36
Air Gap (m)	20	17	20	20
Concrete grade (t/m^3)	C70	C60	C60	C60
Concrete volume (m^3)	9.000	14.000	18.000	21.300
Solid ballast (t)		19.000	26.500	27.500

Table 2 Typical Key Figures Spar Buoys

	Response amplitudes
Surge	10.7 m
Heave	6.6 m
Pitch	5.9 deg

Table 3 Typical response amplitudes semisubmersible.

ITEMS		SPAR BUOY		TYPICAL SEMISUB.
		RETURN PERIOD 1 YEAR	RETURN PERIOD 100 YEAR	RETURN PERIOD 100 YEAR
Sign. wave height	(m)	11	15.5	
Peak period	(s)	12.5-16.5	14.5-18.5	
Natural period - heave	(s)	29.5		
Natural period - pitch	(s)	35.2 (48.5)		
First order amplitudes				
- heave	(m)	1.4	4.8	6.2
- pitch	(deg)	5.1 (4.7)	7.4 (6.6)	7.0
- surge	(m)	4.5	7.7	7.5
Total amplitudes				
- heave	(m)	2.5	7.0	
- pitch	(deg)	6.5	9.5	
Static offset	(m)		10.8	
Total offset	(m)		18.5	

TABLE 4 MOTION CHARACTERISTICS

NOTE: Number in brackets are for an oilfilled platform.

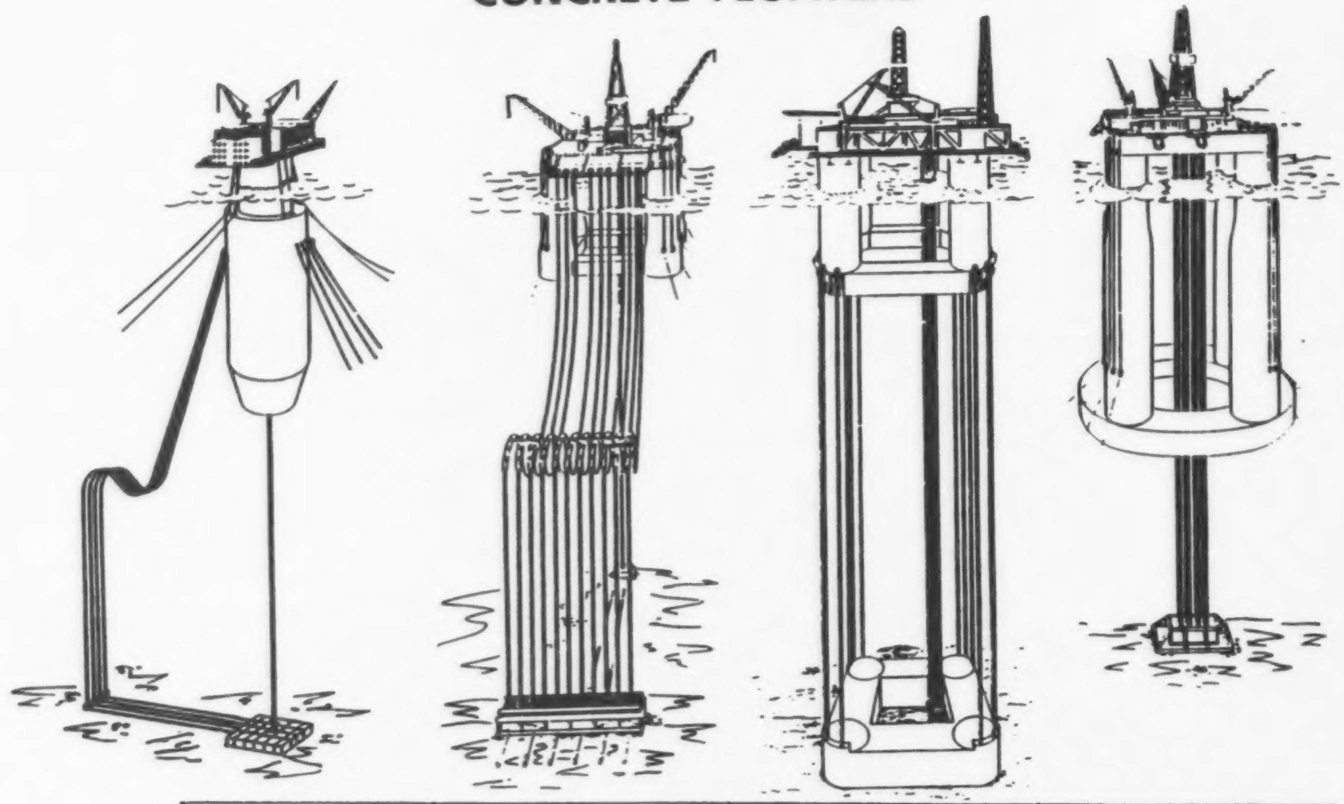
WATER DEPTH	95 M	350 M
No. of anchor lines	12	12
Chain size/length (mm/m)	92 / 1470	76 / 870
Wire size/length (mm/m)	-	96 / 850
Max. environmental force(t)	430	500
Max. tension - intact (t)	470	330
Max. offset - intact (m)	19	24

Table 5 Anchor system properties - semisubmersible

ITEMS		KEY DATA	
TOPSIDE WEIGHT	(t)	5.000	8.000
DRAFT	(M)	110	80
OIL STORAGE	(bbls)	330.000	220.000
WATER DEPTH	(m)	150	130
NO. OF ANCHOR LINES	(m)	8	8
CHAIN SIZE/LENGTH	(mm/m)	84/1350	105/2000
WIRE SIZE/LENGTH	(mm/m)	109/250	-
PRETENSION	(t)	80	80
MAX. ENVIRON. FORCE	(t)	310	470
MAX. TENSION - INTACT (ONE LINE)	(t)	330	520
MAX. OFFSET - INTACT	(m)	11	11

TABLE 6 TYPICAL ANCHORING SYSTEM

CONCRETE FLOATERS



	SPAR BUOY	SEMI	TLP	DEEP FLOATER
PURPOSE	DRILLING / PRODUCTION	EXPLORATION / PRODUCTION	DRILLING / PRODUCTION	DRILLING / PRODUCTION
Water depth (m)	> 150	> 80	> 200	> 200
Wells	Subsea	Subsea	Topsides	Topsides
Oil Storage (bbls)	700.000	700.000	1.500.000 (in foundation)	1.500.000
Topside Weigth (t)	< 25.000	< 25.000	< 60.000	< 50.000
No of Risers	1 - 20	1 -20	1 - 60	1 - 50
Type of Risers	Flexible	Flexible	Rigid + Flexible	Rigid + Flexible

FIG. 1 CONCRETE FLOATERS BY NAC

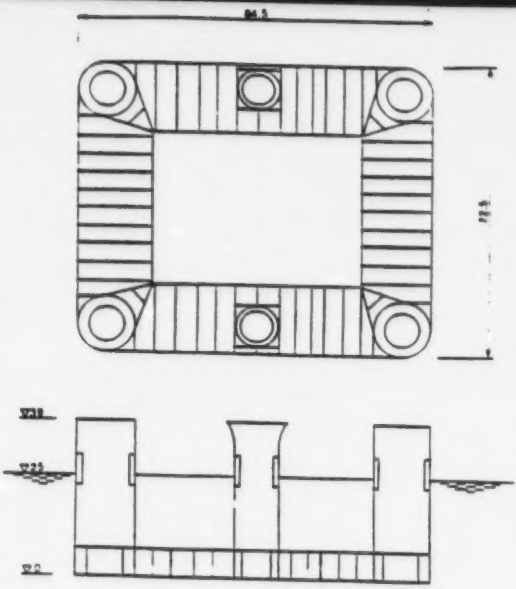

84.5
72.5
∇38
∇25
∇0

FIG. 2 GENERAL VIEW

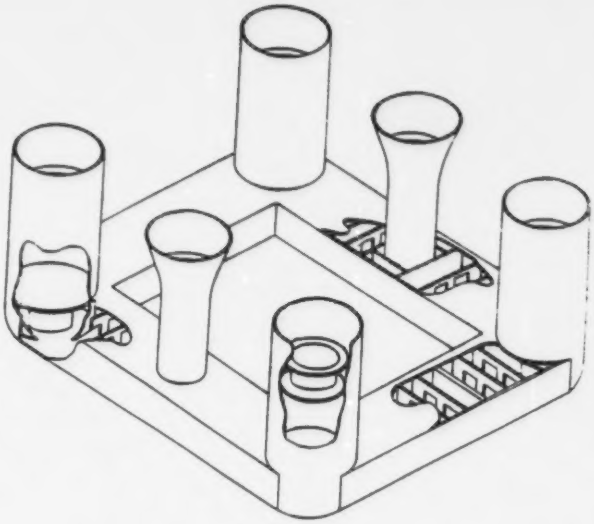


FIG. 3 STRUCTURAL LAYOUT

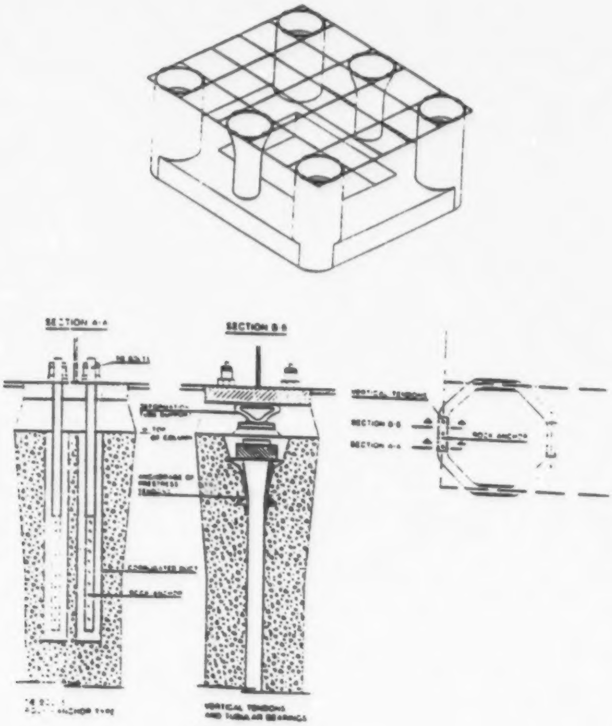

SECTION A-A
SECTION B-B
VERTICAL TENDONS
SECTION B-B
SECTION A-A
ROCK ANCHOR
ROCK ANCHOR
VERTICAL TENDONS
AND TUBULAR BEARINGS

FIG. 4 DECK/COLUMN SUPPORT

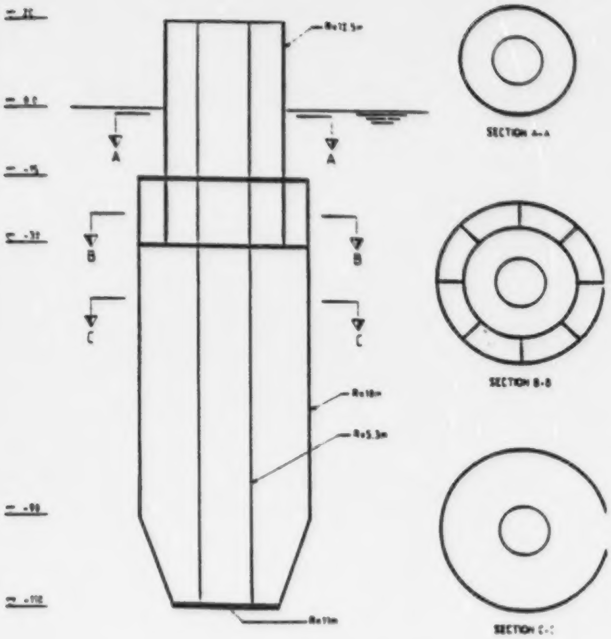

R=12.5m
A
A
B
B
C
C
R=10m
R=5.3m
R=11m
SECTION A-A
SECTION B-B
SECTION C-C

FIG. 5 GENERAL VIEW

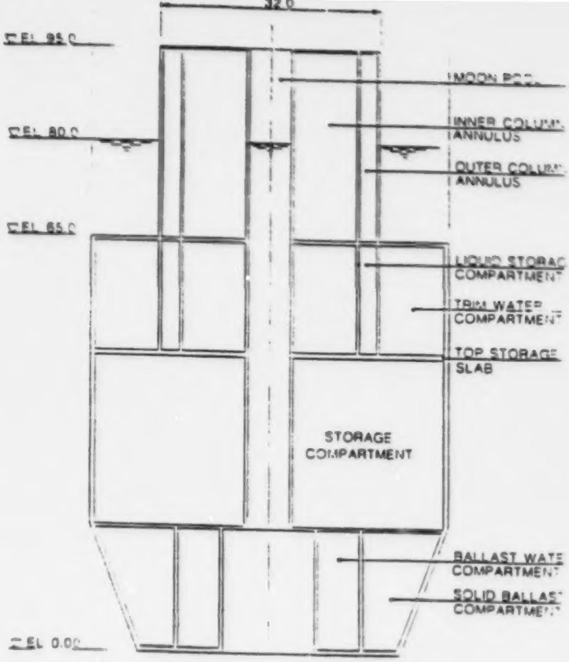
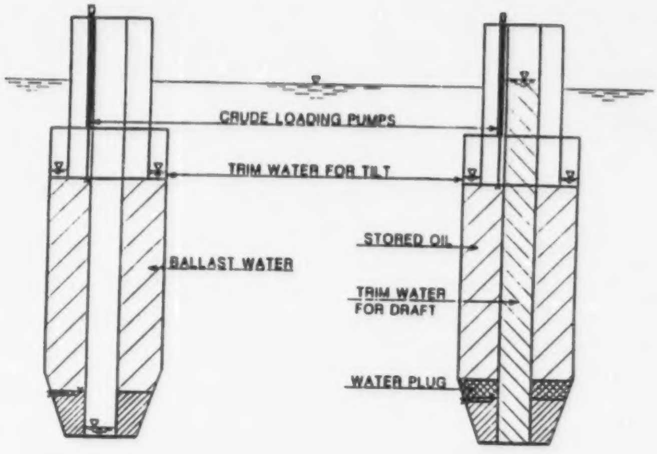

32.0
EL 95.0
EL 80.0
EL 65.0
EL 0.00
MOON POOL
INNER COLUMN ANNULUS
OUTER COLUMN ANNULUS
LIQUID STORAGE COMPARTMENT
TRIM WATER COMPARTMENT
TOP STORAGE SLAB
STORAGE COMPARTMENT
BALLAST WATER COMPARTMENT
SOLID BALLAST COMPARTMENT

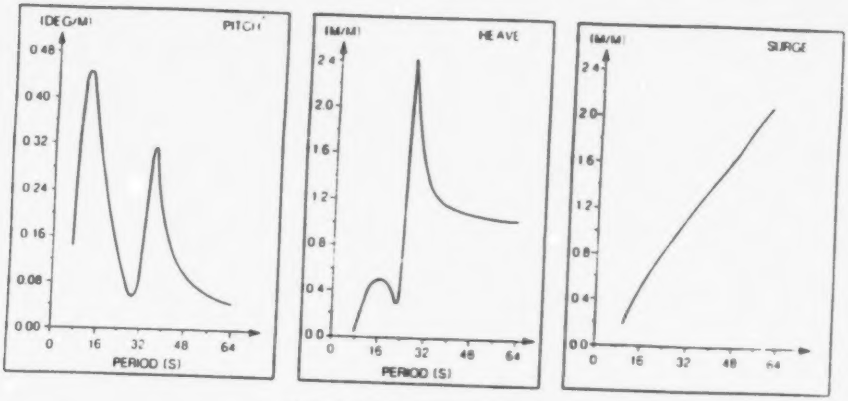
FIG. 6 GENERAL VIEW


CRUDE LOADING PUMPS
TRIM WATER FOR TILT
BALLAST WATER
STORED OIL
TRIM WATER FOR DRAFT
WATER PLUG

NO OIL IN STORAGE

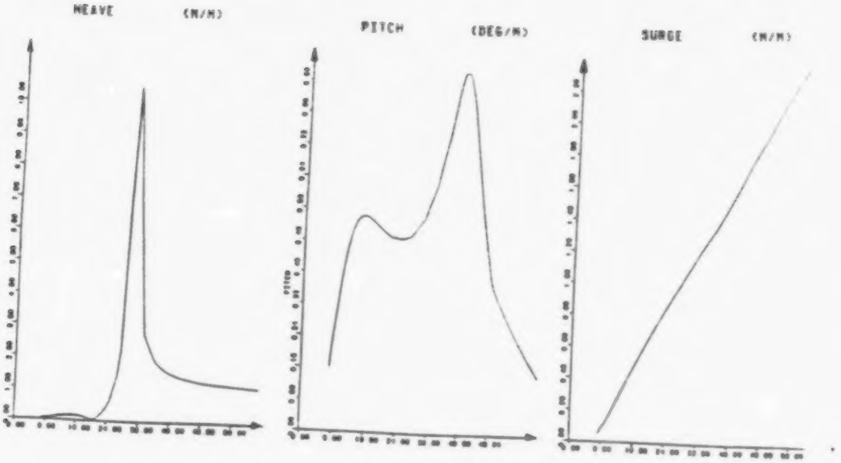
STORAGE FULL OF OIL

FIG. 7 STORAGE AND TRIMMING PRINCIPLES



AMPLITUDE / WAVE AMPLITUDE VS PERIOD

FIG. 8 TRANSFER FUNCTIONS SEMI



TRANSFER FUNCTION (AMPL /WAVE AMPL)

FIG. 9 TRANSFER FUNCTIONS SPAR BUOY

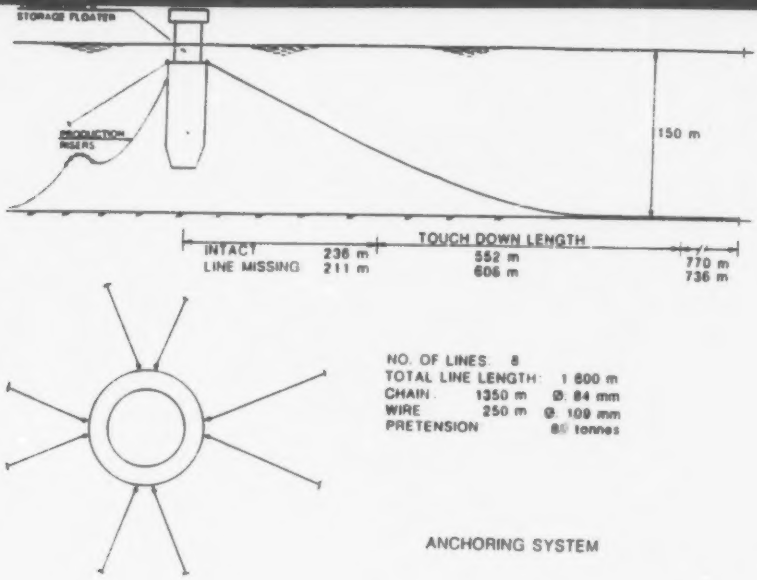

STORAGE FLOATER
PRODUCTION RISERS
150 m
TOUCH DOWN LENGTH
INTACT 236 m 552 m 770 m
LINE MISSING 211 m 606 m 736 m
NO. OF LINES: 8
TOTAL LINE LENGTH: 1 600 m
CHAIN: 1350 m Ø: 84 mm
WIRE 250 m Ø: 109 mm
PRETENSION 80 tonnes
ANCHORING SYSTEM

FIG.10 TYPICAL ANCHORING SYSTEM

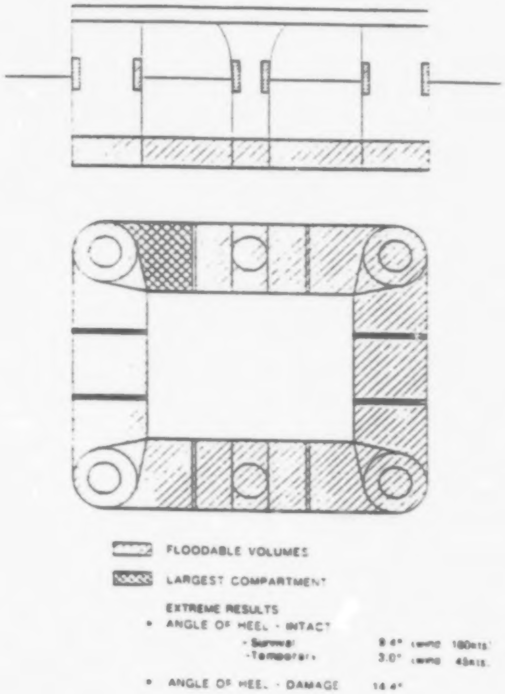

FLOODABLE VOLUMES
LARGEST COMPARTMENT
EXTREME RESULTS
• ANGLE OF HEEL - INTACT
- Survival 8.4° (wind 100kts)
- Temporary 3.0° (wind 45kts)
• ANGLE OF HEEL - DAMAGE 14.4°

FIG. 11 DAMAGE STABILITY

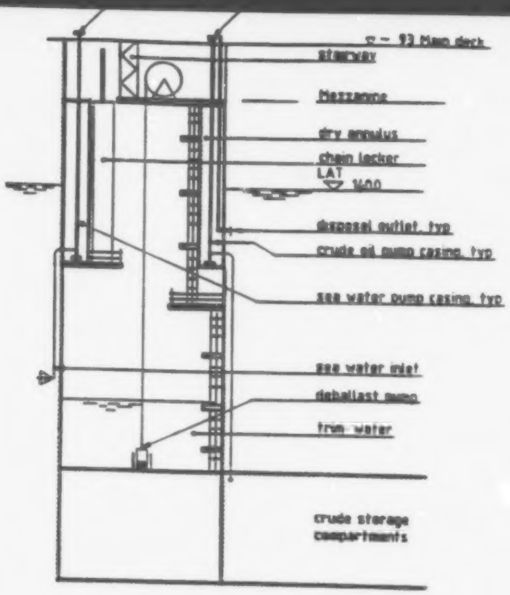

▽ – 93 Main deck
stairway
Mezzanine
dry annulus
chain locker
LAT
▽ 1400
disposal outlet, typ
crude oil pump casing, typ
sea water pump casing, typ
sea water inlet
deballast pump
trim water
crude storage
compartments

FIG.12 HULL OUTFITTING SEMI

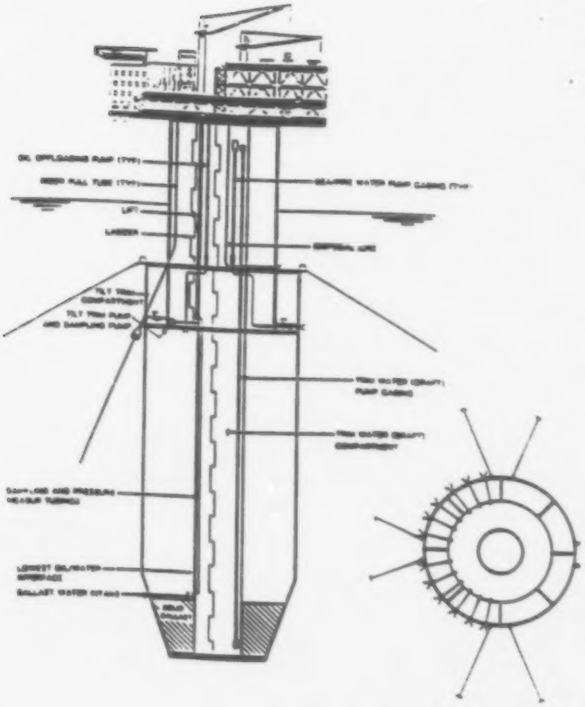

OIL OFFLOADING PUMP (TYP)
RISER PULL TUBE (TYP)
LIFT
LADDER
DISPOSAL LINE
TILT TRIM COMPARTMENT
TILT TRIM PUMP AND SAMPLING PUMP
TRIM WATER (DRAFT) PUMP CASING
TRIM WATER (DRAFT) COMPARTMENT
SAMPLING AND PRESSURE HEADER TUBING
LOWEST OIL/WATER INTERFACE
BALLAST WATER INTAKE
SOLID BALLAST

FIG.13 HULL OUTFITTING SPAR BUOY

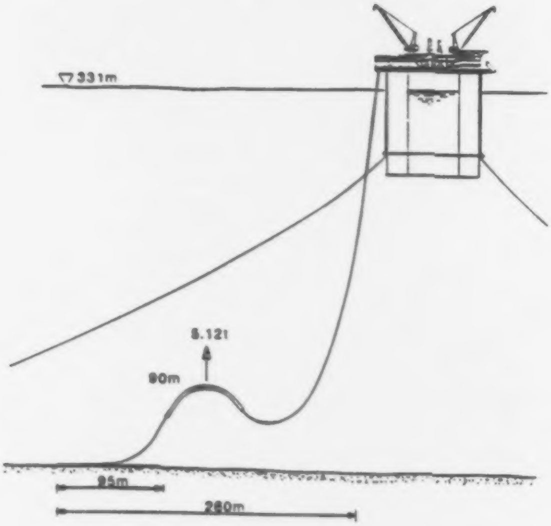

▽331m
S.121
90m
95m
260m

FIG.14 RISER CONFIGURATION

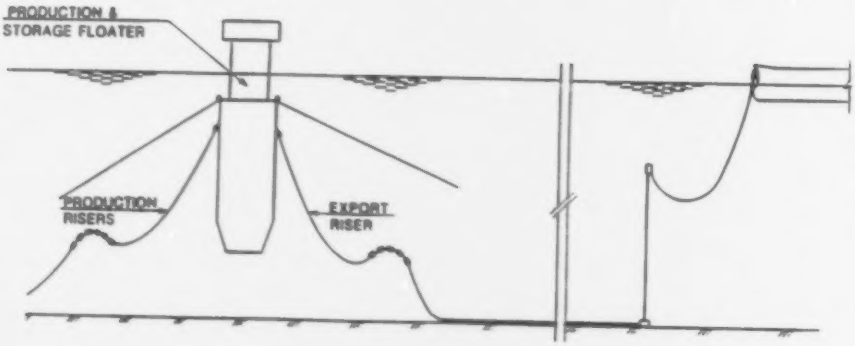

PRODUCTION &
STORAGE FLOATER
PRODUCTION
RISERS
EXPORT
RISER

FIG.15 PROD. RISER CONFIGURATION AND OFFLOADING SYSTEM (UKOLS)

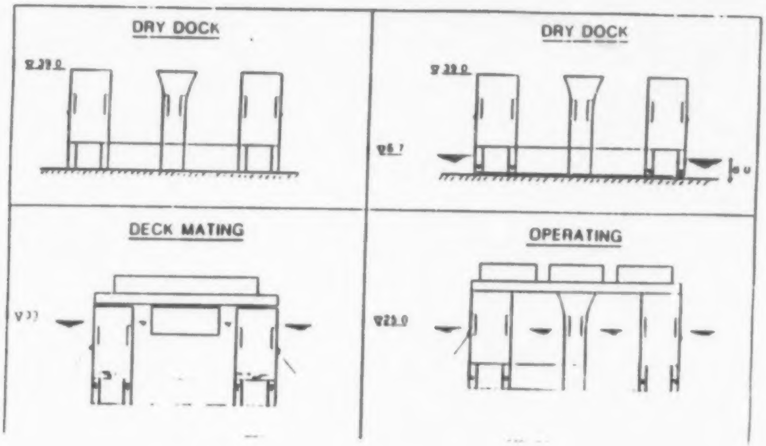

DRY DOCK
∇39.0
DRY DOCK
∇39.0
∇6.7
6.0
DECK MATING
∇33
OPERATING
∇25.0

FIG.16 HULL CONSTRUCTION SEMI

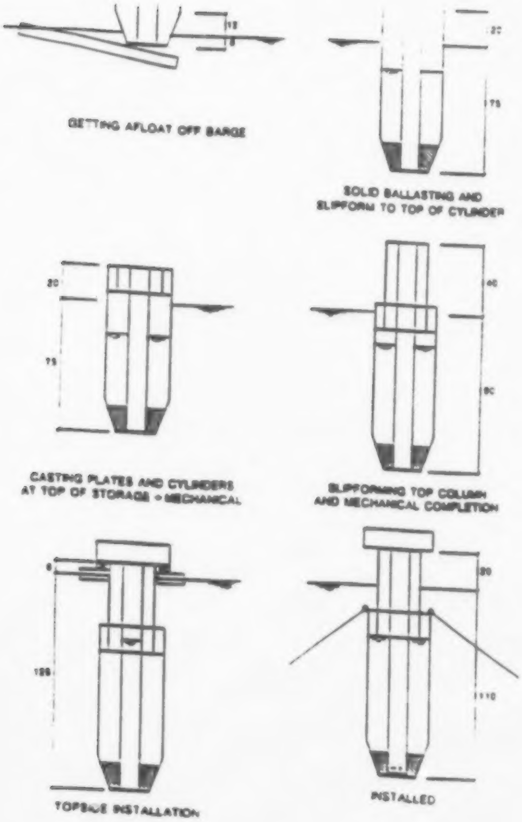

12
8
GETTING AFLOAT OFF BARGE
20
75
SOLID BALLASTING AND SLIPFORM TO TOP OF CYLINDER
20
75
CASTING PLATES AND CYLINDERS AT TOP OF STORAGE + MECHANICAL
40
90
SLIPFORMING TOP COLUMN AND MECHANICAL COMPLETION
8
126
TOPSIDE INSTALLATION
20
110
INSTALLED

FIG.17 HULL CONSTRUCTION SPAR BUOY

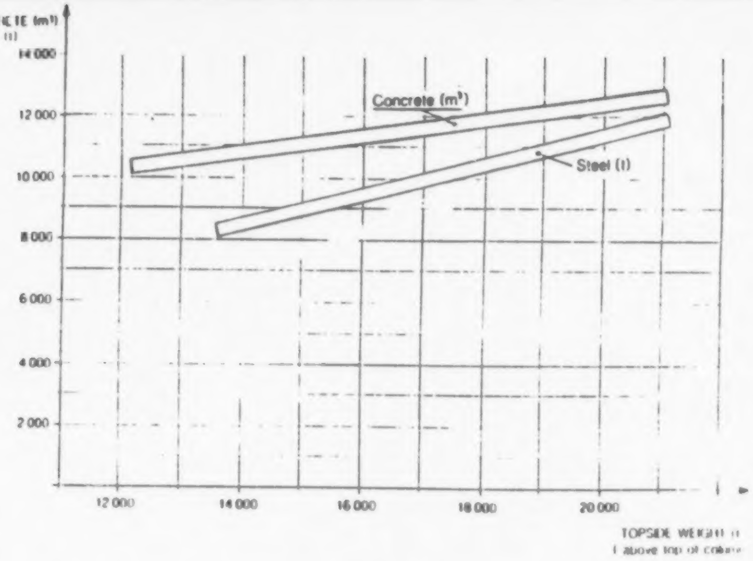


FIG.18 HULL STEEL/CONCRETE VS. TOPSIDE without storage

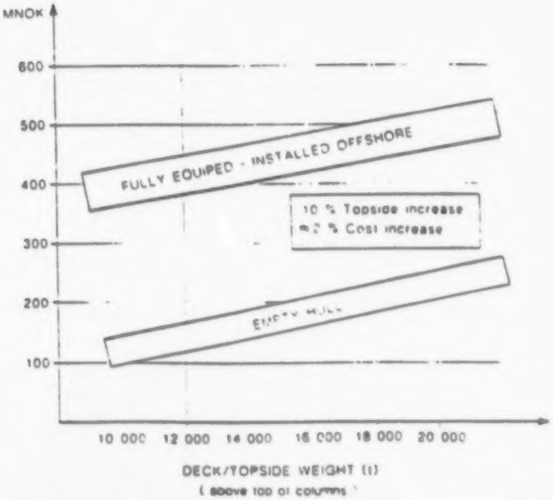


FIG.19 HULL COST VS. TOPSIDE WEIGHT SEMI

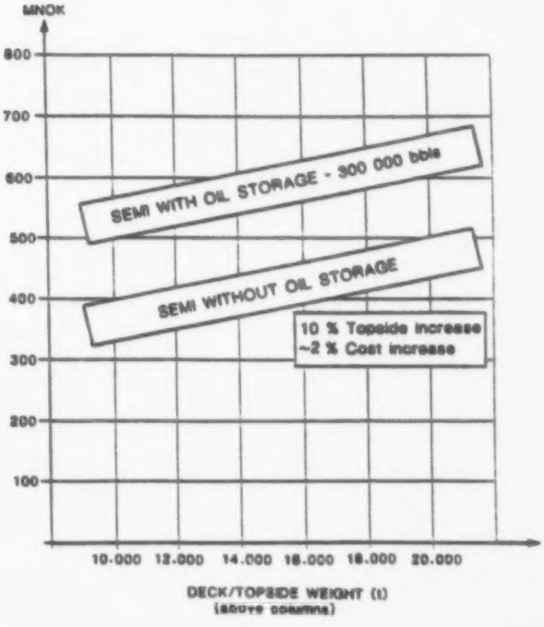


FIG.20 COST VS. TOPSIDE WEIGHT SEMI with oil storage

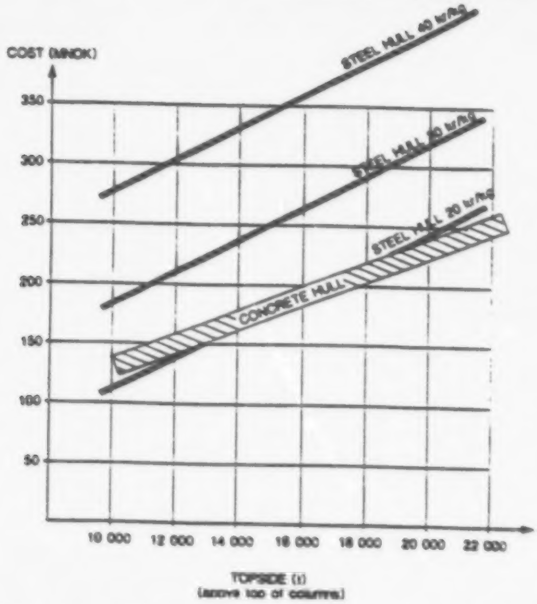


FIG.21 HULL COST STEEL VS. CONCRETE SEMI

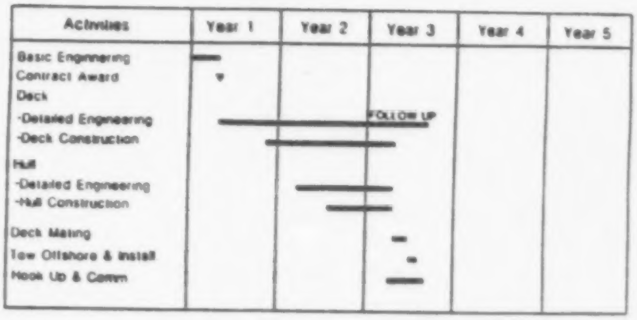


FIG.22 CONSTRUCTION SCHEDULE SEMI

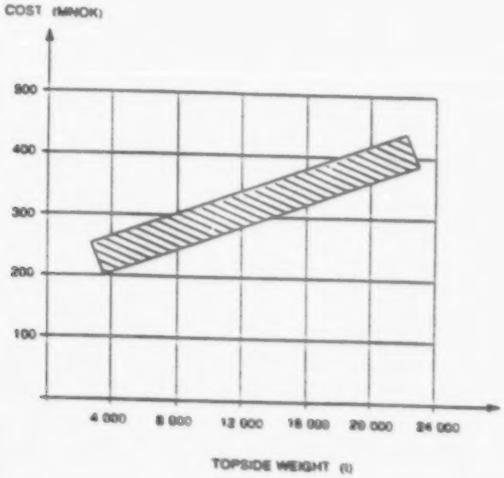


FIG.23 COST VS. TOPSIDE WEIGHT SPAR BUOY

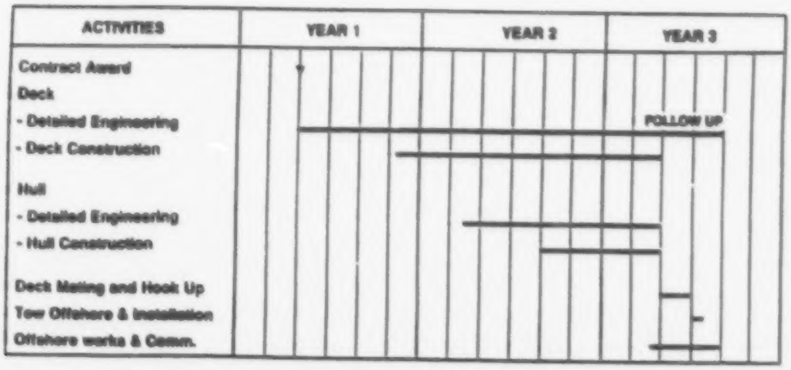


FIG.24 CONSTRUCTION SCHEDULE SPAR BUOY

SPEAKER : **GARETH LEWIS-DAVIES**

COMPANY : **WOOD MACKENZIE AND CO.**

LOCATION: **EDINBURGH, SCOTLAND**

TOPIC : **TRENDS IN CAPITAL AND OPERATING COSTS - THE UK EXPERIENCE**

BIOGRAPHY: Gareth Lewis-Davies is an Assistant Director with County Natwest Wood Mackenzie in Edinburgh, Scotland. He is an oil and gas analyst specializing in upstream field economics in the North Sea. Increasingly, he has been involved in valuing oil and gas properties for the purpose of mergers and acquisitions of companies and assets.

He has an M.Sc. in Energy Policy and Economics from Imperial College, University of London, and has been employed by his present employer since July 1985.

ABSTRACT

TRENDS IN CAPITAL AND OPERATING COSTS - THE UK EXPERIENCE.

The UKCS has evolved since 1965 from a frontier to a mature oil province. Certain trends can be established. Whilst the discovery rate and the average field size has declined, development costs and the present value of projects has not followed similar changes. Therefore, although a province may mature with less oil being discovered and developed, the costs of new developments/barrel may fall and the present value of each new barrel developed may increase. This feature is not solely due to the oil price but by active attempts to reduce costs and to make a better use of existing facilities.

UKCS

RESERVES, COSTS & VALUE

Summary

In this Paper we review the historical prospectivity and development costs of the UKCS and examine the trends which may impact on future activity in the North Sea. Using our extensive database on every significant offshore discovery in UK waters and every field development, we have been able to establish for each year:

- the success ratio
- reserves discovered per exploration well
- finding cost per barrel
- the total present value of reserves discovered
- the total present value per barrel of reserves discovered

For every field development in UK waters, we have also been able to establish for each year:

- number and type of developments
- reserves sanctioned for development
- total capital expenditure per barrel
- total operating costs per barrel
- total present value per barrel of developed reserves

UKCS Discoveries

A number of interesting points emerge. During the 1980s, the high level of drilling has not been supported by the prevailing real oil price but by fiscal changes which has reduced the true cost of drilling a well for a tax efficient oil company. The success ratio, although fluctuating, has remained relatively constant over the last ten years. The amount of reserves discovered per exploration well has declined geometrically since the early 1970s but, due to the nature of the decline curve, the discovery rate has remained constant since the late 1970s.

The cost of finding a barrel of reserves has also remained flat in real terms since 1978. The cost of drilling a well has varied widely over the period and reserves discovered per exploration well has also fluctuated. Movements in these two parameters have tended to offset each other resulting in a relatively constant finding cost over the period.

The total present value of reserves discovered in each year has declined steeply since 1970. However, during the 1980s the total present value on a per barrel basis has started to increase. This has occurred for three main reasons. The value attached to, and the incentive to drill satellite structures has increased through time. Capital and operating cost savings which have been incorporated since the 1986 oil price collapse have impacted on the value attached to recent discoveries. Finally improvements in seismic technology has led to recent and relatively large discoveries in the Eocene. Although the continuing high level of drilling activity may still depress the discovery rate, the quality and value of reserves being discovered remains strong.

UKCS Field Development

Through time the number of developments sanctioned each year has increased but the net amount of reserves and average field size has fallen markedly from the early 1970s.

Capital costs per barrel in real terms shows an increase from the late 1960s to the late-1970s declining thereafter. The early gas fields and the first wave of large oil developments were followed by more expensive oil developments. However, further developments from the 1980s onwards have utilised lower capital cost technology but have incurred higher operating costs through tariff payments for third party use of existing transportation and processing infrastructure.

The forecast new wave of developments which may gain Annex B approval in the near term will not follow the trends which have been established over the last 24 years. The average size of the field is set to increase. Capital costs per barrel may decrease and whilst total operating costs per barrel may increase, overall costs per barrel will fall. Finally the total present value of these new developments compares favourably with developments which took place in the 1980s. It is encouraging that, despite the prevailing low oil price environment, new developments may have greater value than developments seen over the last ten years.

Method

The information required has been collated from three separate sources; the North Sea Service, the North Sea Valuation Service and the Brown Book (Development of the Oil and Gas Resources of the United Kingdom). The following parameters were identified:

- Total UKCS drilling expenditure on combined exploration and appraisal activity from 1976 to 1988 has been taken from the Brown Book. In this paper, the expenditure has been converted into 1989 terms using an inflator series shown in the Green Pages of the North Sea Service. The Brown Book does not split out expenditure between exploration and appraisal wells. For the purpose of this paper we have assumed that the cost of each type of well is identical in any one year. It is then possible to give the assumed cost of a single exploration well.

- CNWM has a database covering all significant discoveries made in the UKCS. Each discovery has been classified under one of five categories depending on the development which has either taken place, will take place or, in our opinion, may take place. The five development categories are as follows:

    - In Production - fields on stream
    - Under Development - field with Annex B but not yet on stream
    - Probable Development - Annex B anticipated in the next two to three years
    - Other Finds (Commercial) - development anticipated in the longer term
    - Other Finds (Uncommercial) - presently regarded as offering no commercial potential.

- To each discovery, we have attributed a discovery date and a total technically recoverable reserve estimate on a proven plus probable basis. Reserves which were established by subsequent appraisal activity has been credited to the discovery well. For 'Other Finds', there is inevitably greater uncertainty over the recoverable reserve base.

- The total capital cost (excluding decommissioning expenditure) for each field development has been calculated and expressed in 1989 terms.

- Total direct operating costs for the life of each field development have also been calculated on the same basis. In addition both tariff receipts and tariff payments have been calculated separately to give total operating cost information.

- Latest reserve information is expressed on a recoverable proven plus probable basis.

- The total present value for each of the finds has been calculated. The value of the developments have been credited to the years in which the finds were made. For all the discoveries, regardless of in which development category the finds are placed, the following assumptions have been made:

  - an oil price of $17.75 in 1989, $17.50 in 1990, escalating at 1% per annum in real terms (approximately 6% per annum nominal) until 1995. From 1996 onwards it is assumed that the rate of increase will be 3% per annum in real terms (approximately 8.15% in nominal terms).

  - The $/£ exchange rate is assumed to decline steadily to $1.60/£1 by 1991 and to remain constant thereafter.

  - The total present value has been discounted to the start of 1990 at a nominal discount rate of 12.5%.

For fields in production, under development or those regarded as probable developments, we have field cash flows from which a total present value can be calculated. In addition to these commercial fields, there are over 170 other UKCS finds which are too uncertain at this stage for us to have field specific cash flow models. Rather we have valued these reserves by comparison with a series of 12 model fields, which have incorporated our latest estimates of capital and operating costs for a range of potential developments. We believe this series of model fields covers the range of likely future developments.

UK Model Fields

Code	Field Type
A	Incremental oil
B	Stand alone oil (30-35 m.bbls)
C	Stand alone oil (50-100 m.bbls)
D	Stand alone oil (100-200 m.bbls)
E	Stand alone oil (200-400 m.bbls)
F	Uncommercial Oil
G	Incremental gas
H	Stand alone gas (250-500 BCF)
I	Stand alone gas (500-2500 BCF)
J	Uncommercial gas
K	Commercial gas/condensate
L	Uncommercial gas/condensate

- The total present value of the commercial fields ignores the value of tax synergy derived from an oil company's collection of assets including cross field allowance. In addition, the cost of exploration and appraisal activity to the oil companies will be less than stated as all the large companies which drill the bulk of UKCS wells are able to shelter some 84% of the cost against tax. The methodology that we have used examines the prospectivity from the view of the nation as a whole ('UK plc'). At this level tax synergies no longer apply; the full cost of drilling a well is always met albeit in varying proportions by the oil companies and the government. if the cost to the country of finding and developing reserves is greater than the value of those reserves, no tax synergies would redress the problem.

Results

- A total of 2134 exploration and appraisal well starts were made between 1964 and end-1989, of which some 36% were appraisal wells (chart 1). In general, the amount of drilling has increased through time with two marked peaks in 1974 and 1984 occuring some two to three years after major oil price hikes. Overall, the level of drilling activity does not follow the prevailing real oil price (chart 2). In particular the ability since 1982 to offset exploration and appraisal expenditure against PRT has supported a level of drilling activity at a time of falling oil prices in real terms. The ratio of exploration/appraisal wells has inevitably declined through time as the number of discoveries which can be appraised increases. In addition recent discoveries are increasingly more complex features requiring proportionately more appraisal work.

- A total of 302 discoveries have been made up until end-1989 (chart 3). There are two distinct periods when an unusually large number of discoveries were made. in 1975, 23 finds occurred whilst in 1984, 29 finds were recorded. The number of finds is a function, in part, of the number of exploration wells drilled in each year. The success ratio gives a better indication of success giving the proportion of exploration wells which are successful. Between 1965 and 1988 the success ratio between 1964 and 1988 is some 23%. From chart 4 it can be seen that the success ratio has fluctuated about this mean for the last five years reflecting that the UKCS still remains prospective if the success ratio is used as the parameter.

- The amount of reserves discovered is perhaps a more important indicator (chart 5). A total of over 38 billion barrels of oil equivalent has been discovered up until end-1989. This consists of 24 billion barrels of liquids (62%) and 82 TCF of gas (38%). Two distinct major periods of reserves discovery have occurred. In 1966, prior to any major oil exploration activity, some 22 TCF of gas was discovered. The major oil provinces were discovered in the period 1970 to 1975 peaking in 1974 when some 5.3 billion barrels of oil equivalent was discovered.

- It is clear from chart 5 that certain oil and gas reserves have been discovered at particular periods over the last twenty five years. A major proportion of gas reserves were discovered in the southern North Sea during the 1960s. A second period of gas discovery occurred in the mid 1970s in association with major oil discoveries in the central and norther North Sea. During the 1980s the proportion of gas/oil discovered has increased reflecting interest in the gas/condensate prospective acreage in the central North Sea and, in recent years, renewed gas interest in the southern North Sea.

- Chart 6 illustrates the discovery rate which is defined as the amount of reserves discovered per exploration well in any one year. The most successful year using this parameter in 1966 when some 3.9 billion barrels of reserves were found after a total of 20 exploration wells had been drilled. This gives a discovery rate of 195 m.boe/exploration well. A second successful period occurred at the start of the 1970s when the first major oil discoveries were made. In 1971 the discovery rate was some 133 m.boe/exploration well. Since then the discovery rate has declined almost geometrically. By the nature of the decline curve the discovery rate from 1976 to the present has remained roughly constant.

- An additional method of measuring the prospectivity of the North Sea is to examine the finding cost. The Brown Book gives annual capital expenditure for combined exploration and appraisal activity. Using this information in conjunction with the number of wells starts and reserves discovered, it is possible to indicate the cost of finding a barrel of reserves. This is illustrated in the following chart 7. In real terms the cost of finding a barrel of reserves has remained constant since 1978 with the odd exception of 1985. The relative constant finding cost has occurred for a number of diverse reasons. The cost of drilling a well has varied widely over the period and reserves discovered per exploration well has also fluctuated. Movements in these two parameters have tended to offset each other resulting in a relatively constant finding cost over this period.

- Earlier in this paper we identified the number and size of the reserves but not the quality. In the table below, we have shown the discoveries in terms of the development category under which each find has been classified.

	Type of Find					
Category (%)	On Stream	Under Development	Probable Development	Other Prospects Commercial	Other Prospects Uncommercial	Total
Number of Finds	24	5	15	32	24	100
Oil Equivalent reserves	61	4	17	13	5	100
Oil Reserves	63	3	16	11	7	100
Gas Reserves	56	6	17	17	4	100
Total Present Value	82	2	8	8	0	100

In summary, the proportion of discovered gas reserves on stream is lower than for oil reserves reflecting the generally held view that the UK has significant undeveloped gas reserves, particularly in the central North Sea. One point which has not been illustrated is that the proportion of discoveries that are on stream declines through time. Conversely the proportion of "other finds" increases through time.

- A total of 89 fields gained Annex B approval up until end-1989 of which 19 fields are currently under development and have yet to commence production (Chart 8). In general terms, the number of developments sacnctioned in each year has grown over time. Despite the 1986 oil price collapse the greatest number of field developments achieved in one year occurred in 1988 when some 14 developments were sanctioned.

- As a consequence of improved infrastructure and technology, the type of development, whether conventional platform, floating production system or subsea system, has become more diverse through time. The first floating production system was not sanctioned until 1978 and the first subsea field was not approved until 1983. Since then, the application of these technologies has increased. Out of the total number of developments, 70% are conventional platforms, 9% are floating production systems and 21% are subsea systems. However, although floaters and subsea systems comprise 30% by number they will recover only 5% of reserves covered by the study.

- Since 1965 recoverable reserves totalling 24.7 billion barrels of oil equivalent have been sanctioned for development of which 36% are gas reserves (Chart 9). In general terms, the amount of reserves approved for development in each year has fallen through time since the early 1970s. Reserves sanctioned between 1971 and 1974 represents 44% of total reserves approved over the last 24 years. In 1989 only 377 million barrels of oil equivalent was approved for development.

- The combination of an increasing number of field developments per year and a decrease in total reserves sanctioned each year has resulted in a drastic fall in the average size of development (Chart 10). In 1971 the average field size was 2,600 million barrels whilst by 1989 it had fallen by 98% to 42 million barrels.

- Total capital expenditure (excluding decommissioning) amounting to 69.6 billion in 1989 terms has been committed over the last 24 years (Chart 11). The large developments in the early 1970s constitute some 48% of total capital committed to date. Again a decline curve can be seen illustrating that capital expenditure has fallen in real terms. Capital expenditure committed in 1989 was only 7% of that committed in the peak year of 1974.

- On the basis of our estimates, a total of 53.1 billion in 1989 terms will be incurred in direct operating costs to recover reserves from all the fields sanctioned up until end-1989 (Chart 12). Again the major oil developments in the early-1970s constitute the largest number of direct operating expenditure comprising 50% of total direct operating costs incurred and expected to be incurred.

- A more representative measure of costs is to express them on a per barrel basis. Capital costs per barrel have averaged £2.82/boe over the last 24 years (Chart 13). This measure of cost grew between the late 1960s to the late 1970s but has fallen since due to the introduction of cost saving technology and the use of low capex/ high opex developments. For example recent satellite developments are low capital projects but pay higher operating costs in the form of tariffs. The total operating cost per barrel (including trariffs) has averaged £2.01/boe over the last 24 years (Chart 14). It has remained fairly constant in real terms since the early 1970s despite increasing tariff costs. When all costs, both capital and operating, are measured on a per barrel basis, total costs per barrel have increased between 1967 and 1977 and, in general terms, have declined thereafter down to £4.07/boe (Chart 15).

- Projects which have been sanctioned over the last 24 years have, on our estimates, a combined total present value on a post tax basis of £56.7 billion (Chart 16). Some 69% of this value is from developments sanctioned between 1971 and 1974. On a per barrel basis this same period procures the most valuable developments. Although value per barrel fell from about £3.00/boe in the mid-1970s, the value per barrel for developments in the 1980s has remained remarkably constant (Chart 17). The one exception is BP's Cyrus which, due to its innovative technology and R&D nature, is a "loss leader".

Comparison of Results with Probable Developments

CNWM constantly reviews the field economics of probable developments which may gain Annex B approval over the next three to four years. For each development a discounted cash flow can be constructed to calculate the series of variables discussed previously in this article. The following table compares 48 ring fenced probable developments with the average of all fields between 1965 and 1989 and the average of fields between 1980 and 1989 inclusive.

Variable		All Developments 1965-1989	1980s Developments 1980-1989	Probables 1990-1994
Sample Size	number	89	60	48
Average field size (mean) m.boe		259	98	127
Capital cost/boe	£/boe	2.84	3.06	2.02
Direct Operating cost/boe	£/boe	2.17	2.10	1.81
Total Operating cost/boe	£/boe	1.95	2.64	2.99
Total costs/boe	£/boe	4.79	5.70	5.01
Present Value/boe	£/boe	2.40	0.76	0.90

Conclusion

The forecast new wave of developments will not follow the trends which have been established over the last 24 years. If the trends were to be extrapolated into the 1990s one would expect new fields to be smaller in size, have higher costs per barrel and to have lower value per barrel. However, improved technology, cost savings and increased use of existing infrastructure may lead to cheaper projects with greater value despite increased indirect operating costs such as tariff payments. In addition the proposed development of previously large, uncommercial gas/ condensate fields and a spate of relatively large recent discoveries have increased the average field size. Although the value per barrel for new developments is substantially lower than the average to date, it is encouraging that, despite the prevailing low price environment, new developments may have greater value per barrel than developments that were sanctioned during the 1980s.

Chart 1

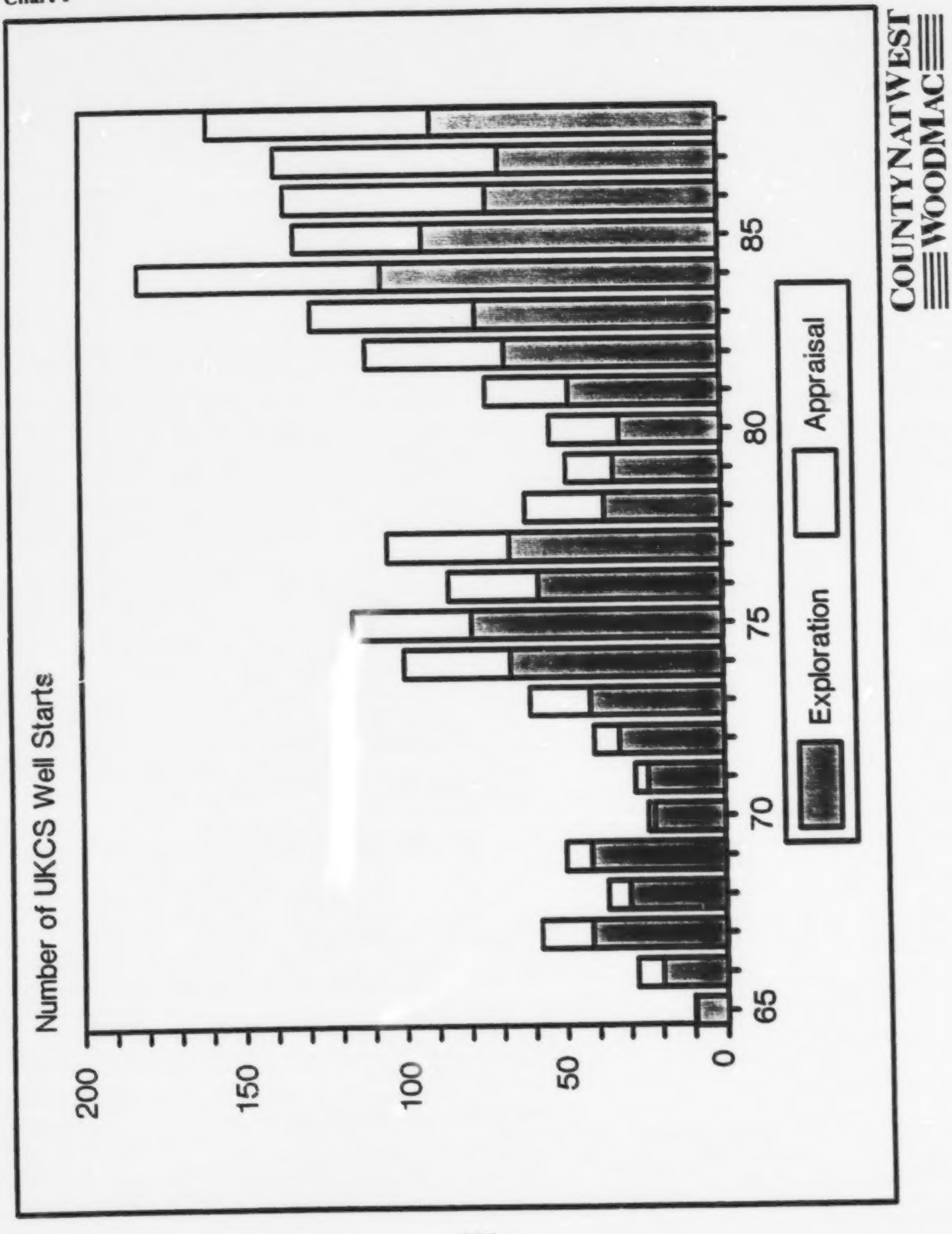
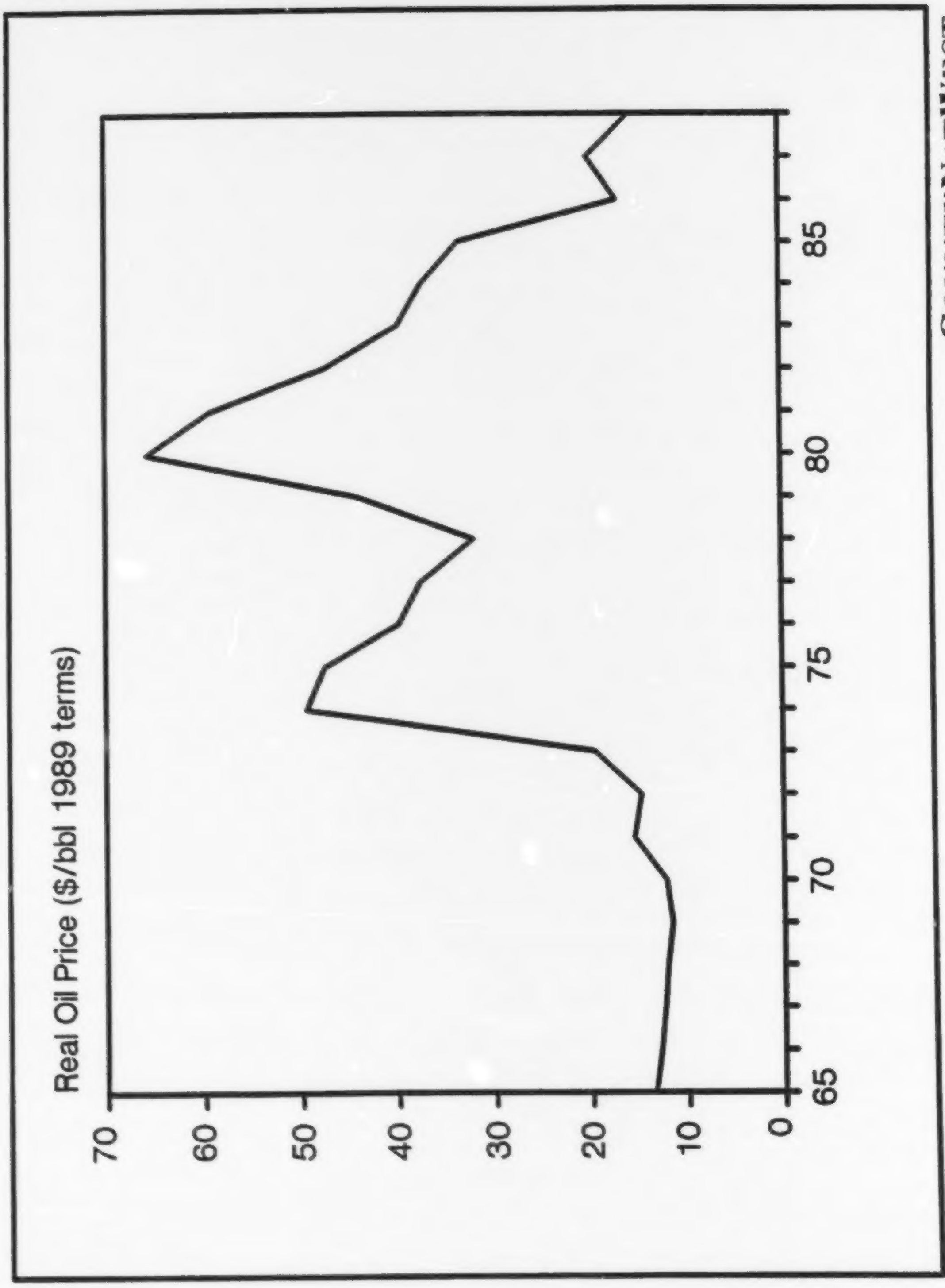
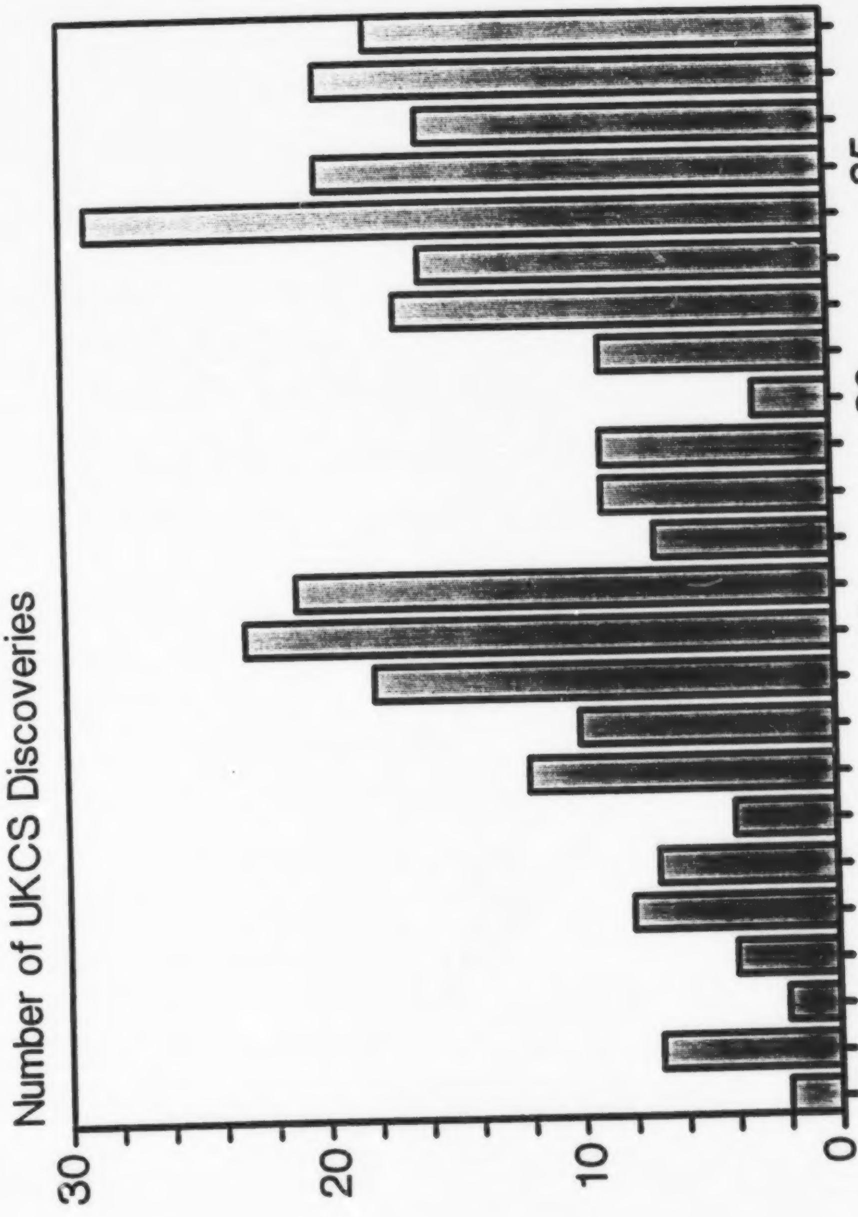

Number of UKCS Well Starts
200
150
100
50
0
65
70
75
80
85
Exploration
Appraisal
COUNTY NATWEST
WOODMAC

Chart 2



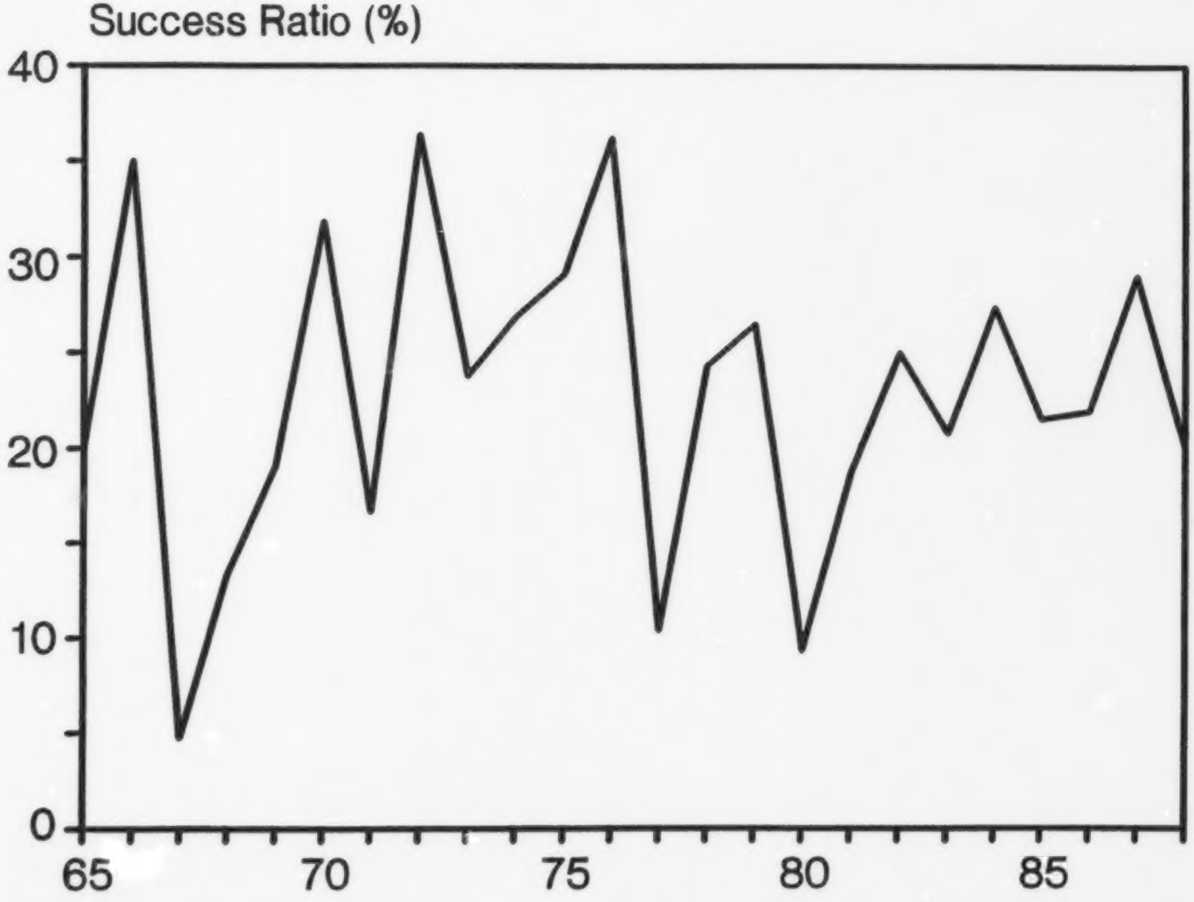
COUNTYNATWEST WOODMAC

Chart 3



COUNTYNATWEST
WOODMAC

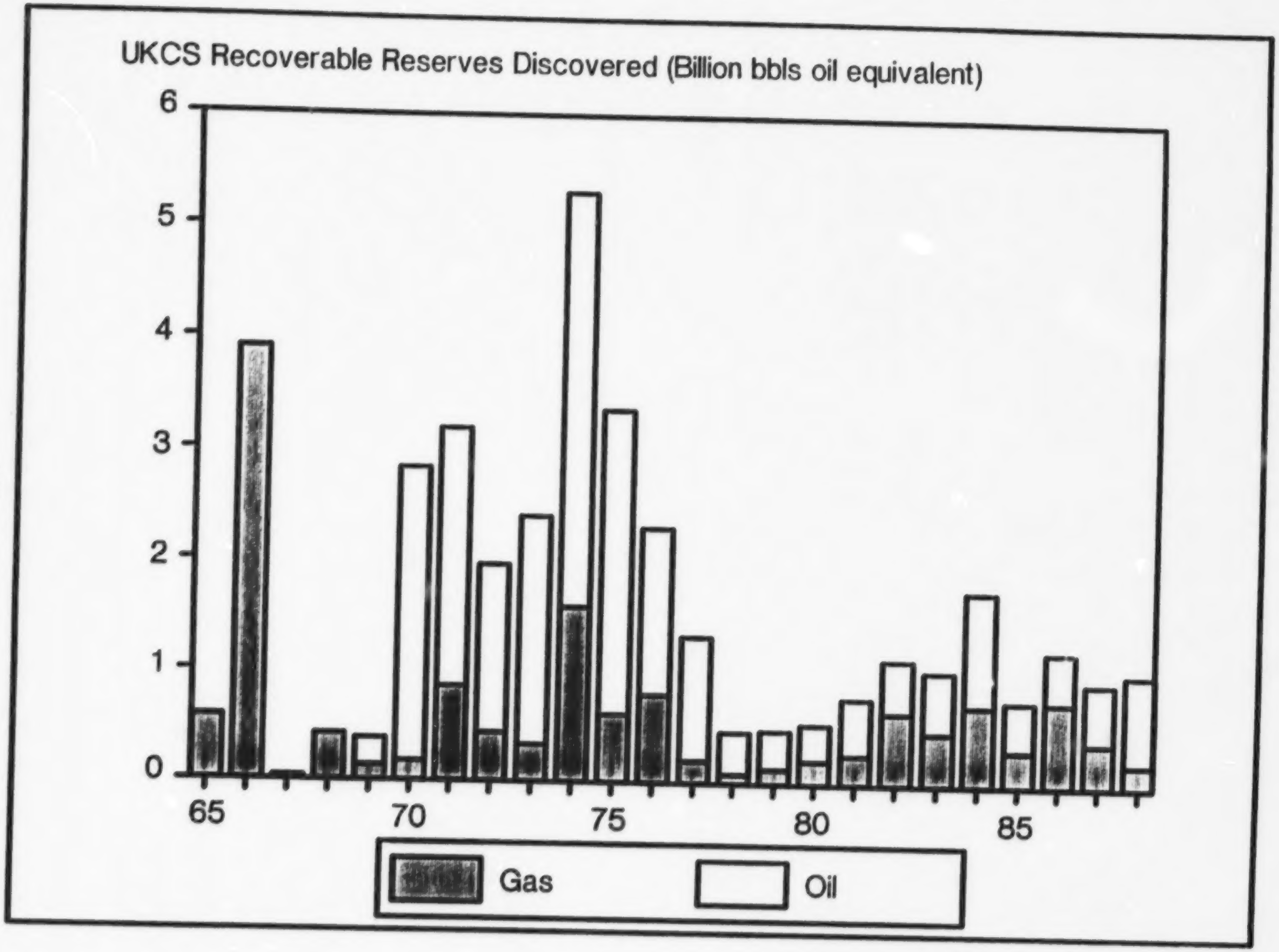
Chart 4



Success Ratio is the proportion of exploration wells that find hydrocarbons .

COUNTYNATWEST
WOODMAC

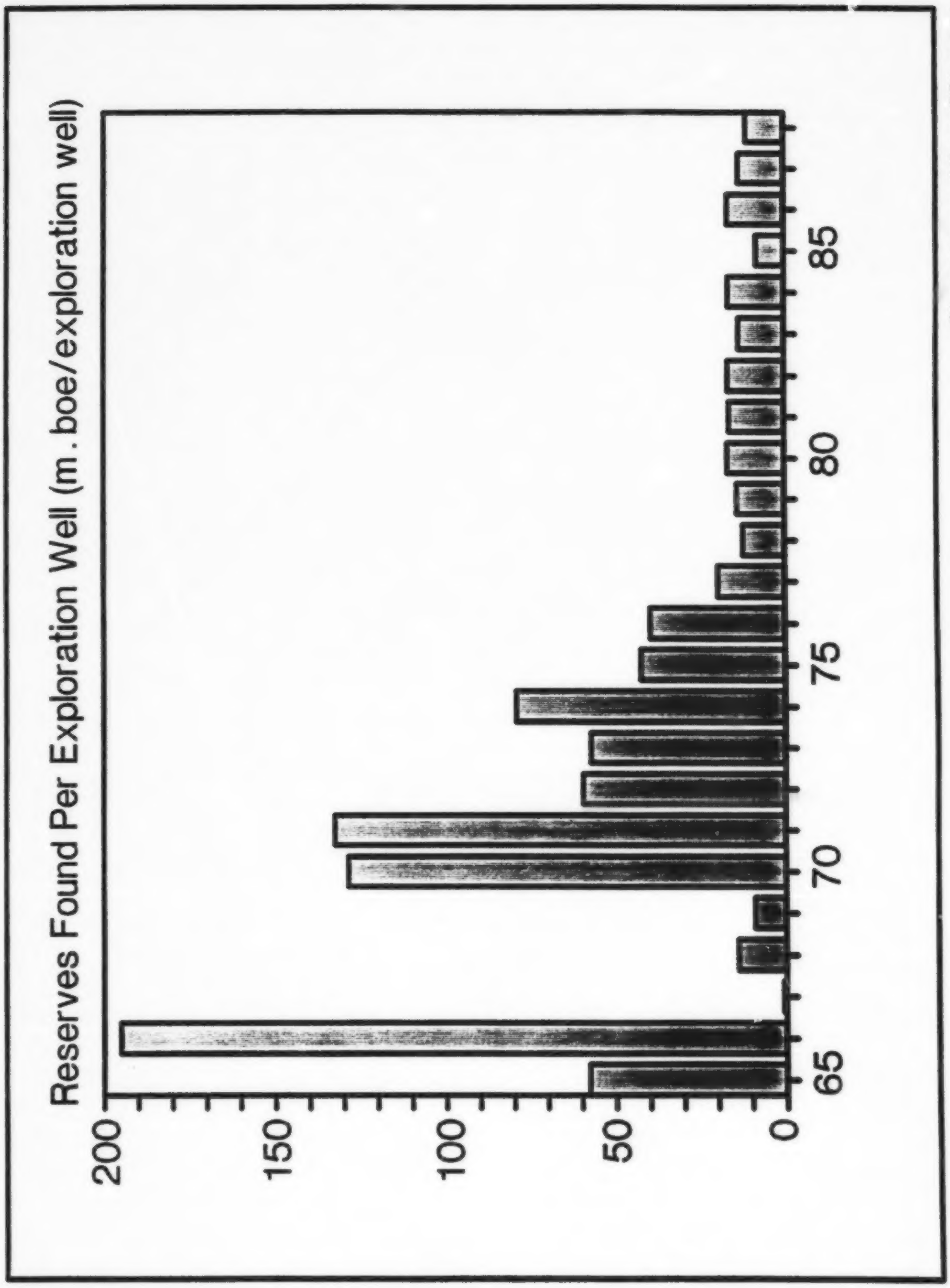
Chart 5



UKCS Recoverable Reserves Discovered (Billion bbls oil equivalent)

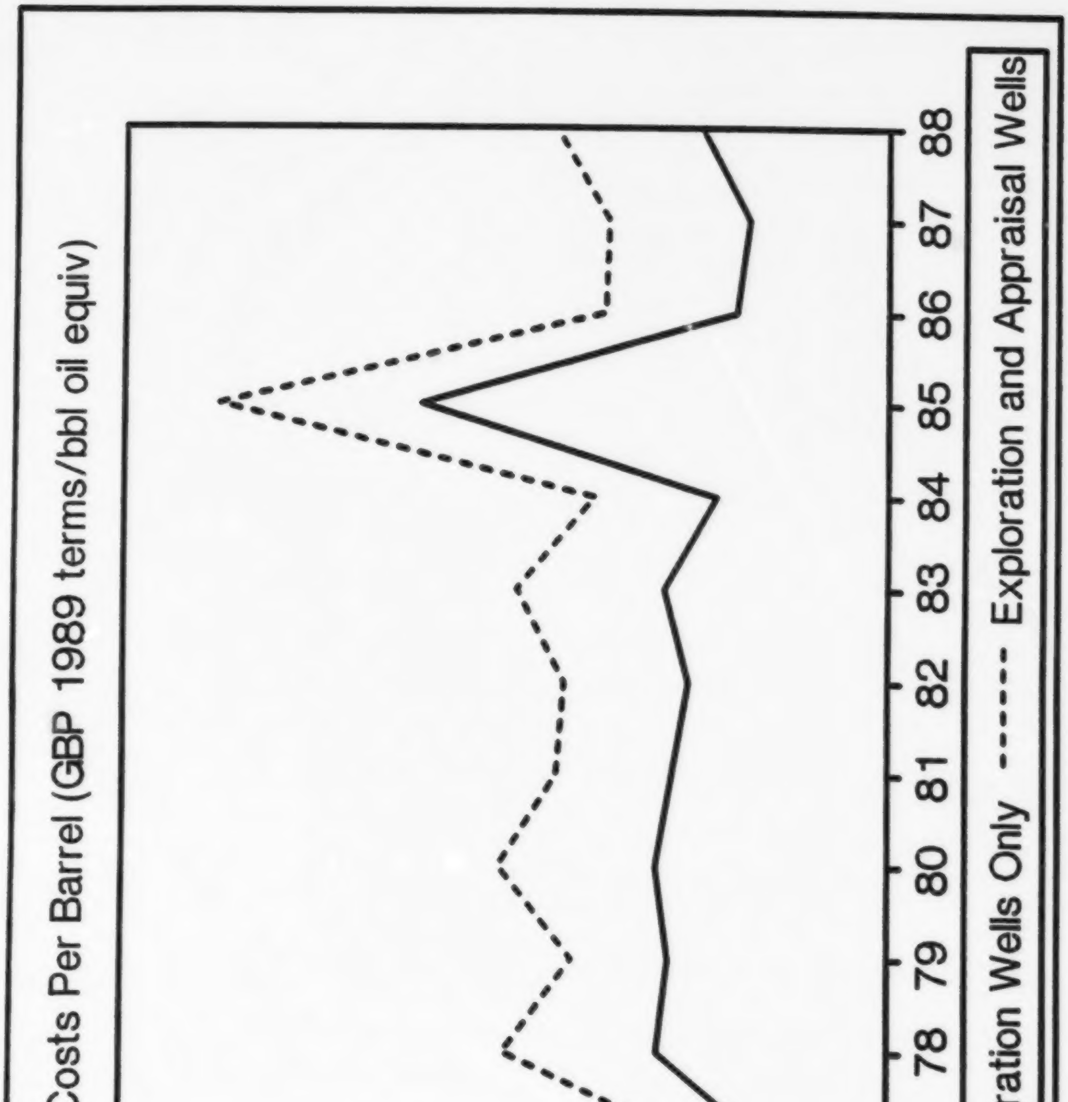
COUNTY NATWEST
WOODMAC

Chart 6



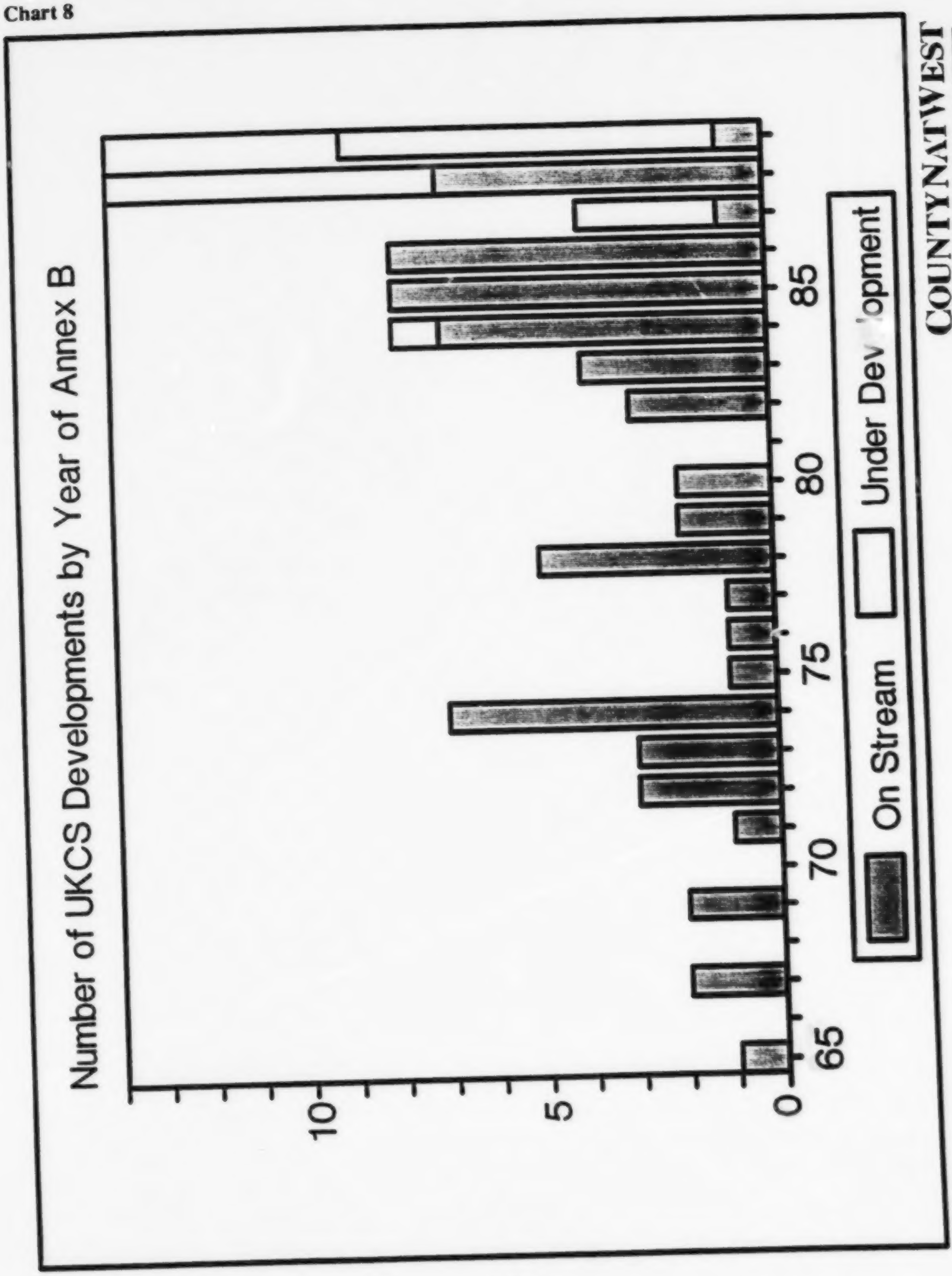
COUNTYNATWEST
WOODMAC

Chart 7



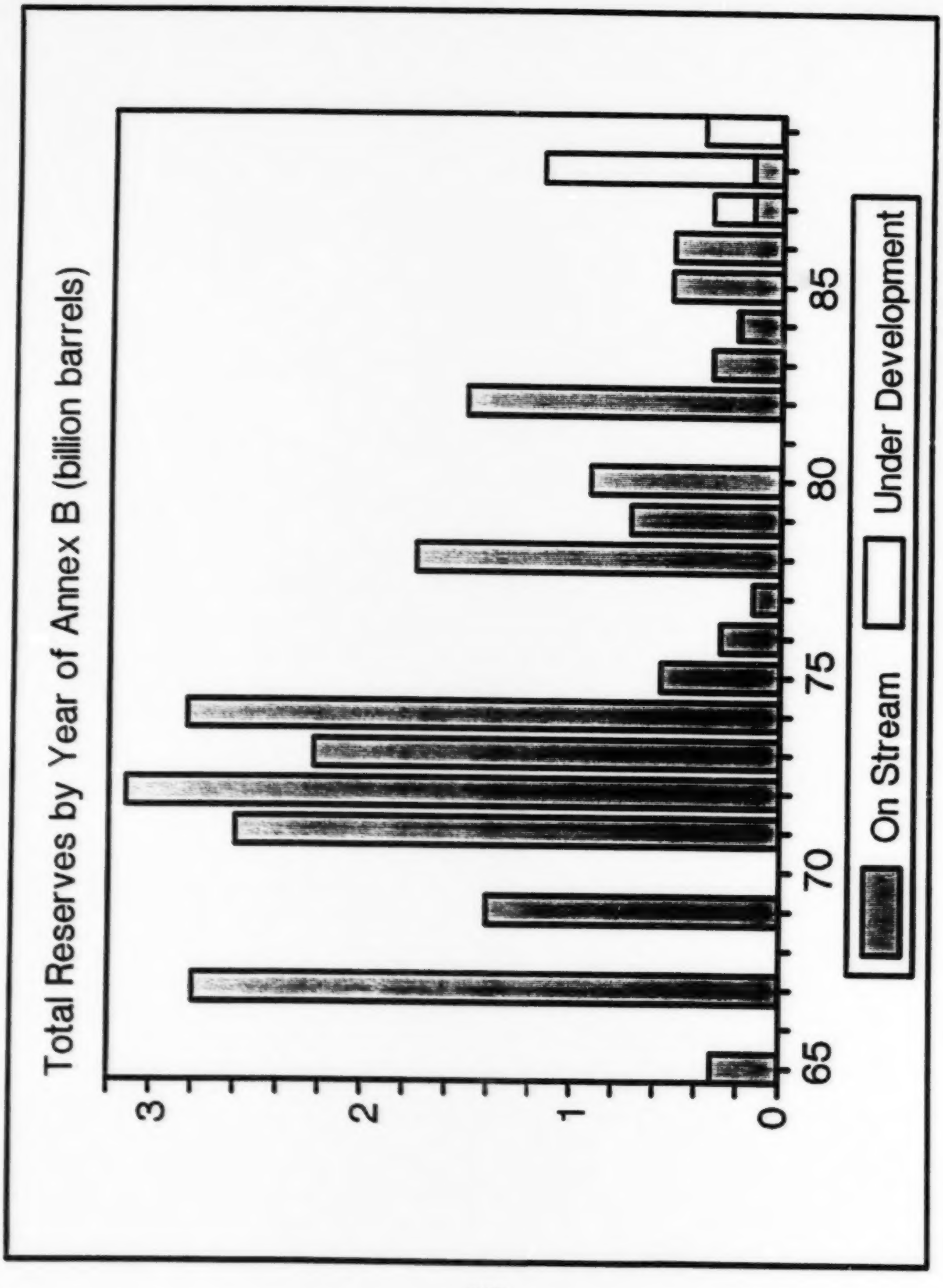
COUNTYNATWEST
WOODMAC

Chart 8



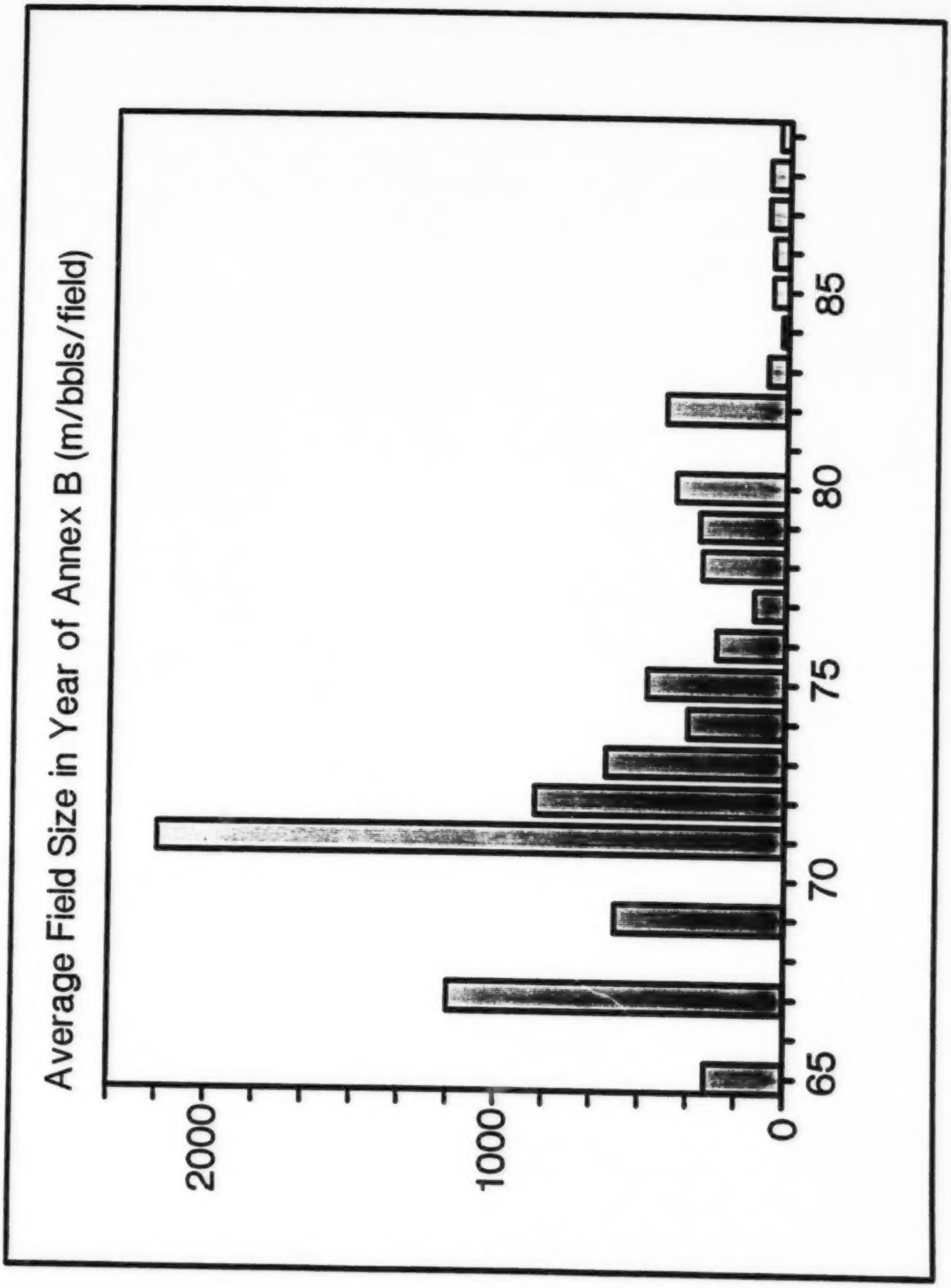
COUNTYNATWEST
WOODMAC

Chart 9



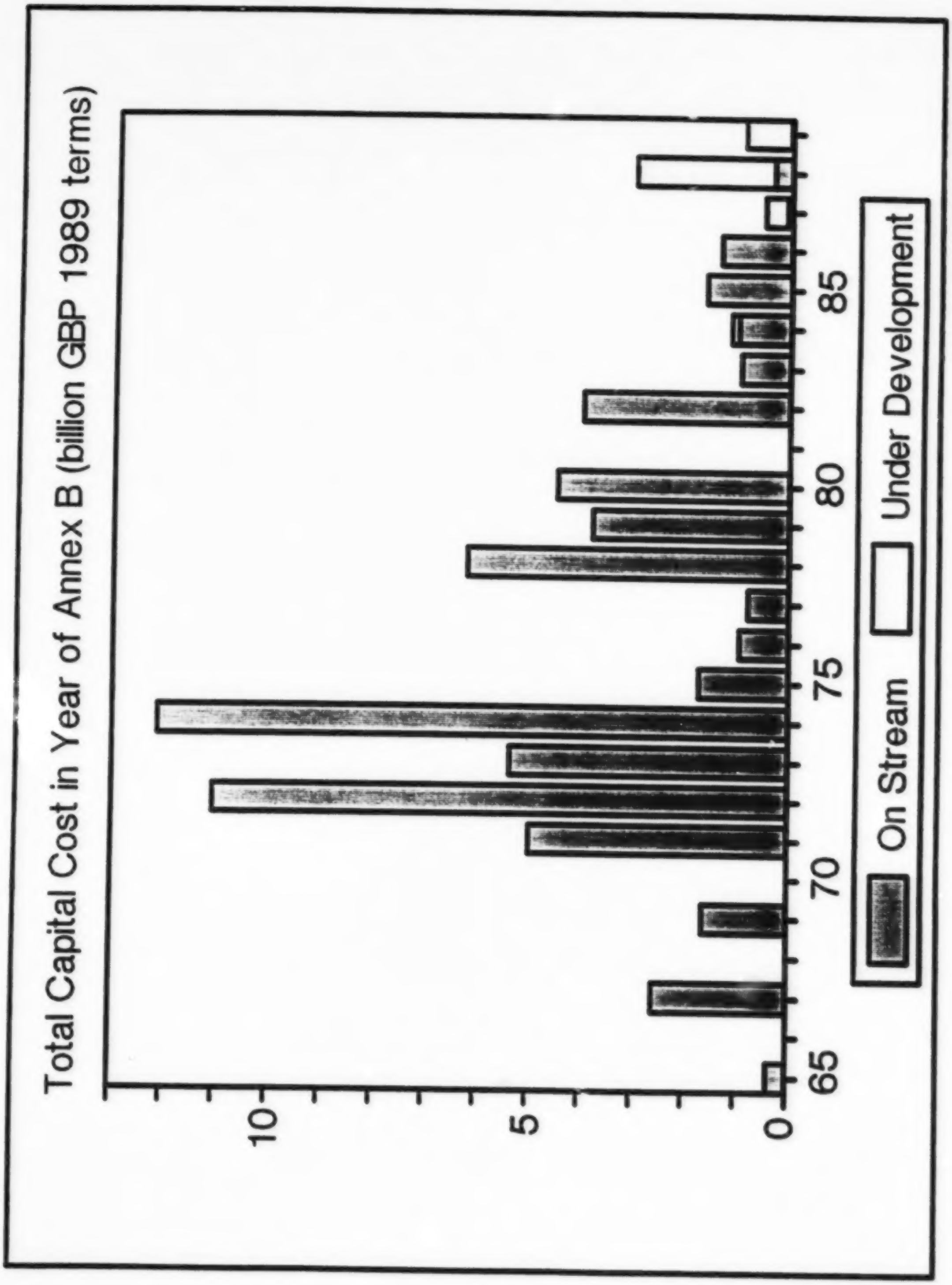
COUNTYNATWEST WOODMAC

Chart 10



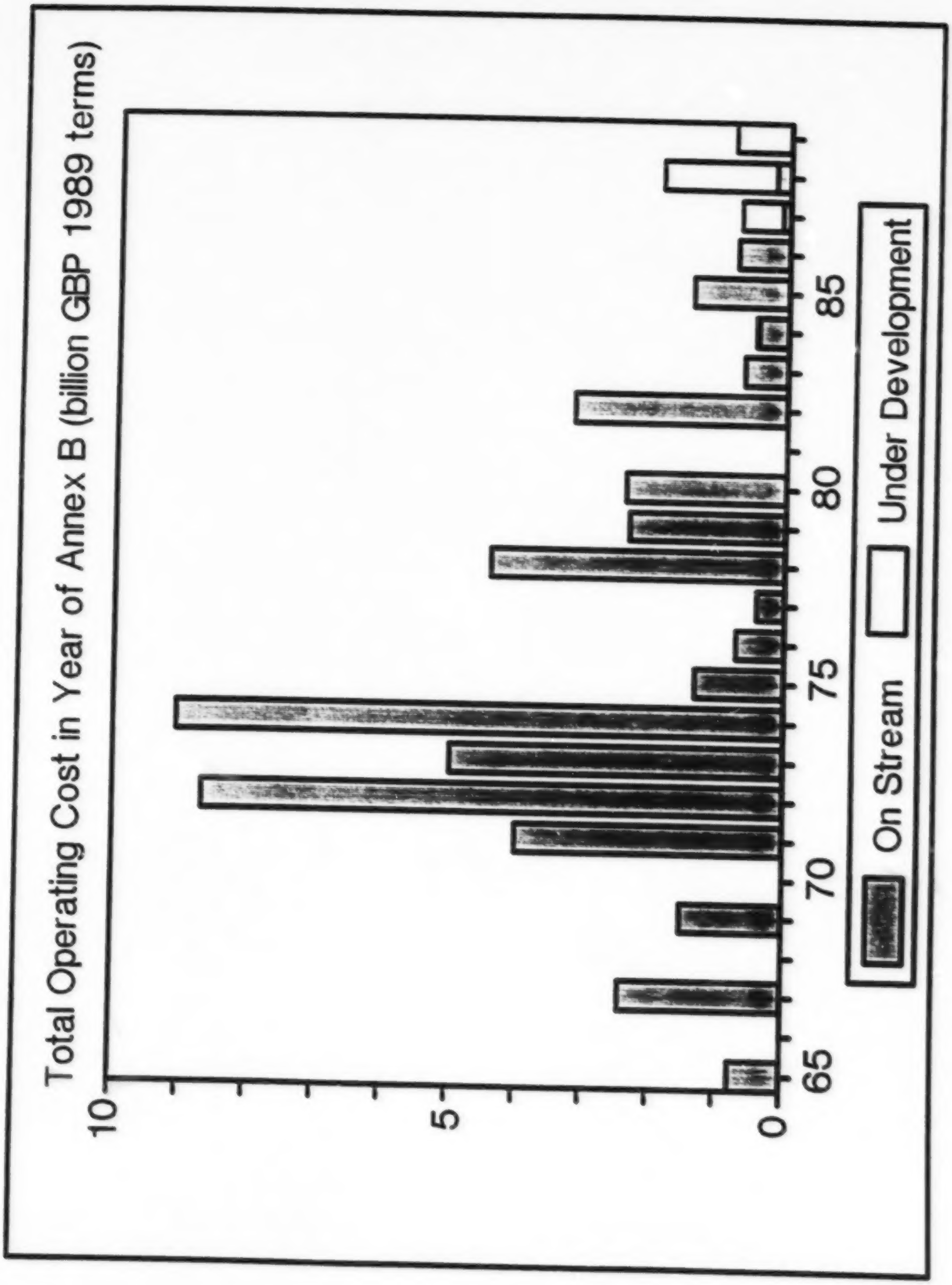
COUNTYNATWEST
WOODMAC

Chart 11



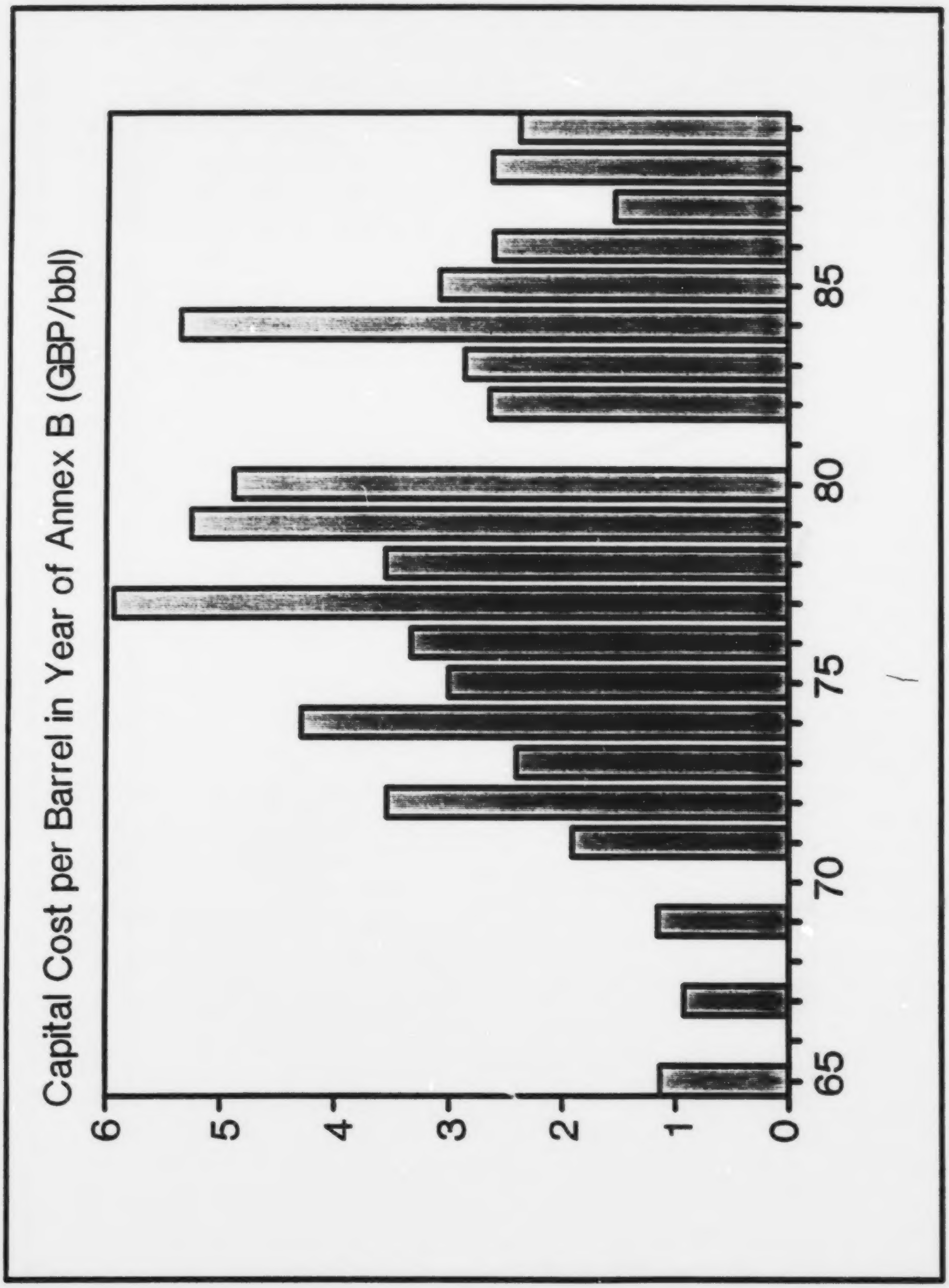
COUNTYNATWEST
WOODMAC

Chart 12



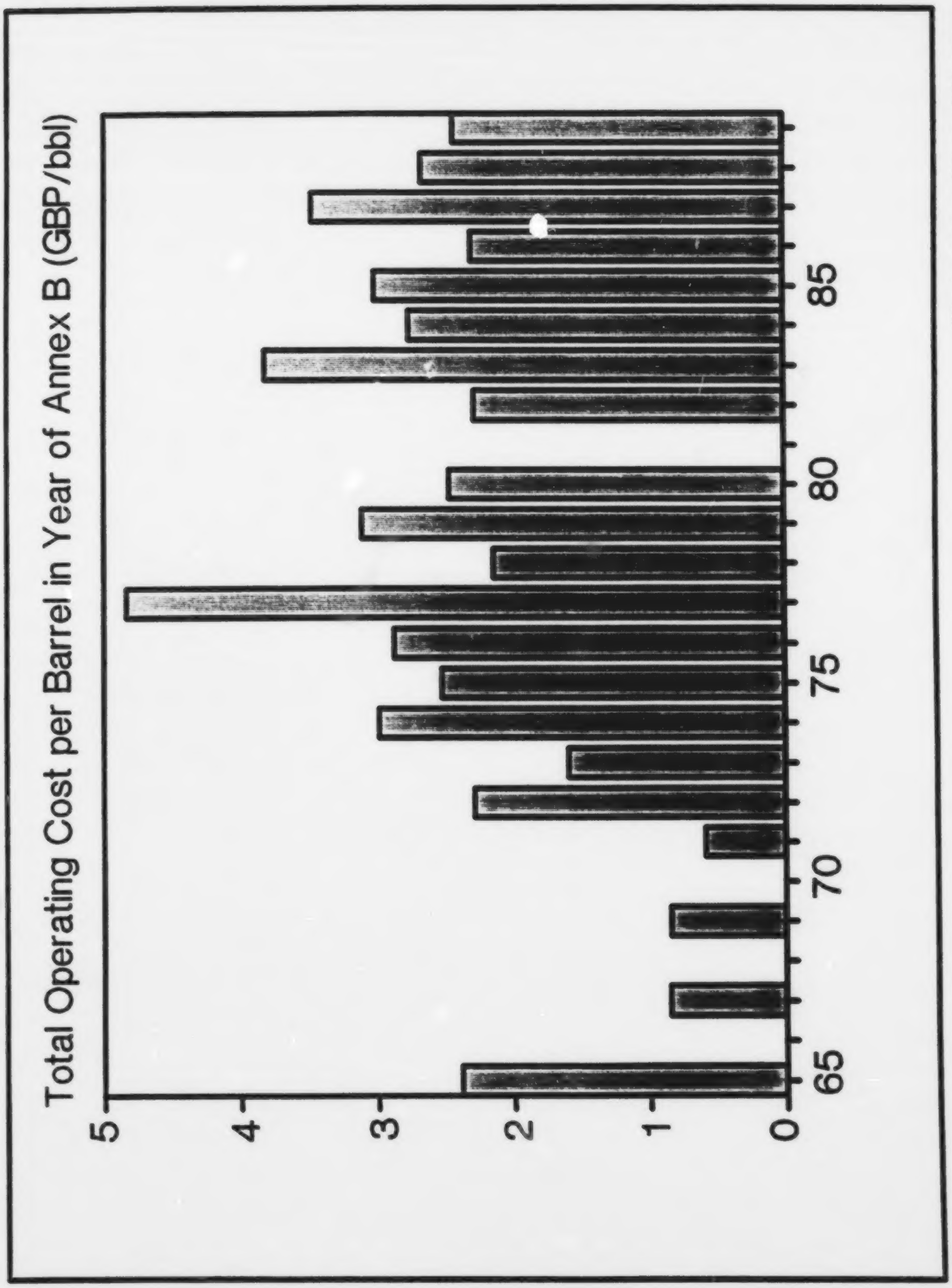
COUNTYNATWEST
WOODMAC

Chart 13



COUNTYNATWEST
WOODMAC

Chart 14



COUNTYNATWEST
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Chart 15

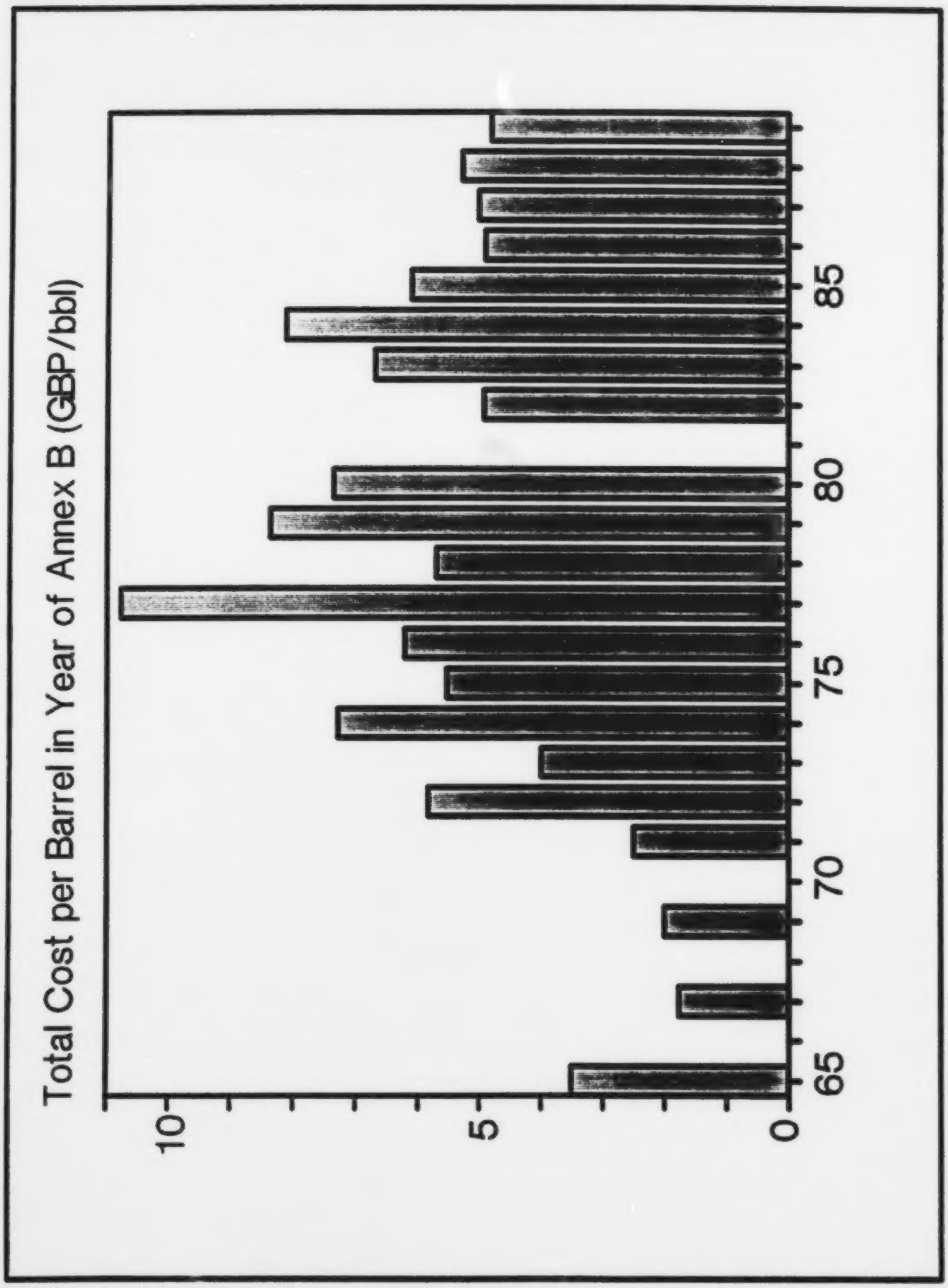
Total Cost per Barrel in Year of Annex B (GBP/bbl)
10
5
0
65
70
75
80
85
COUNTYNATWEST
WOODMAC

Chart 16

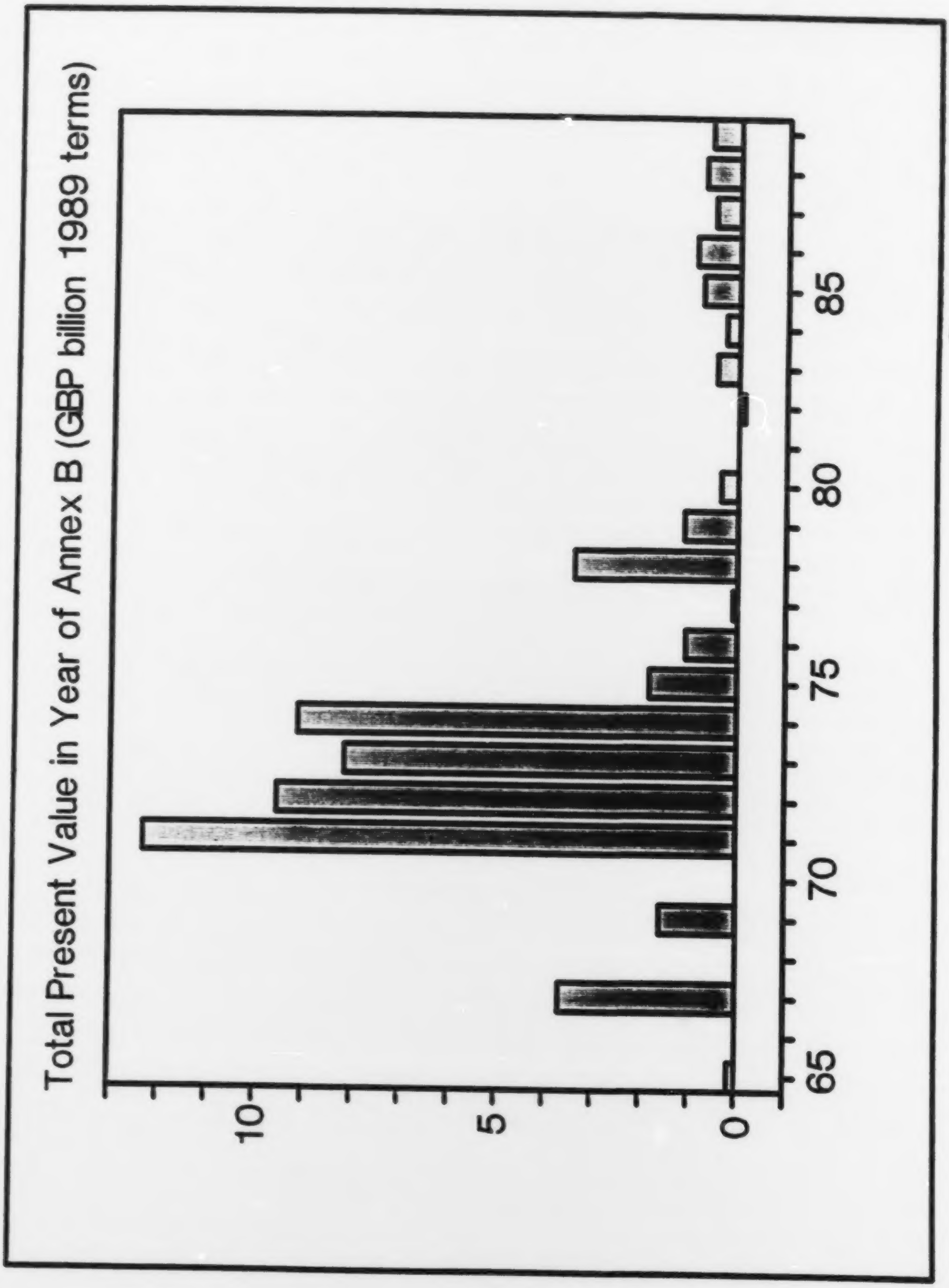

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Chart 17

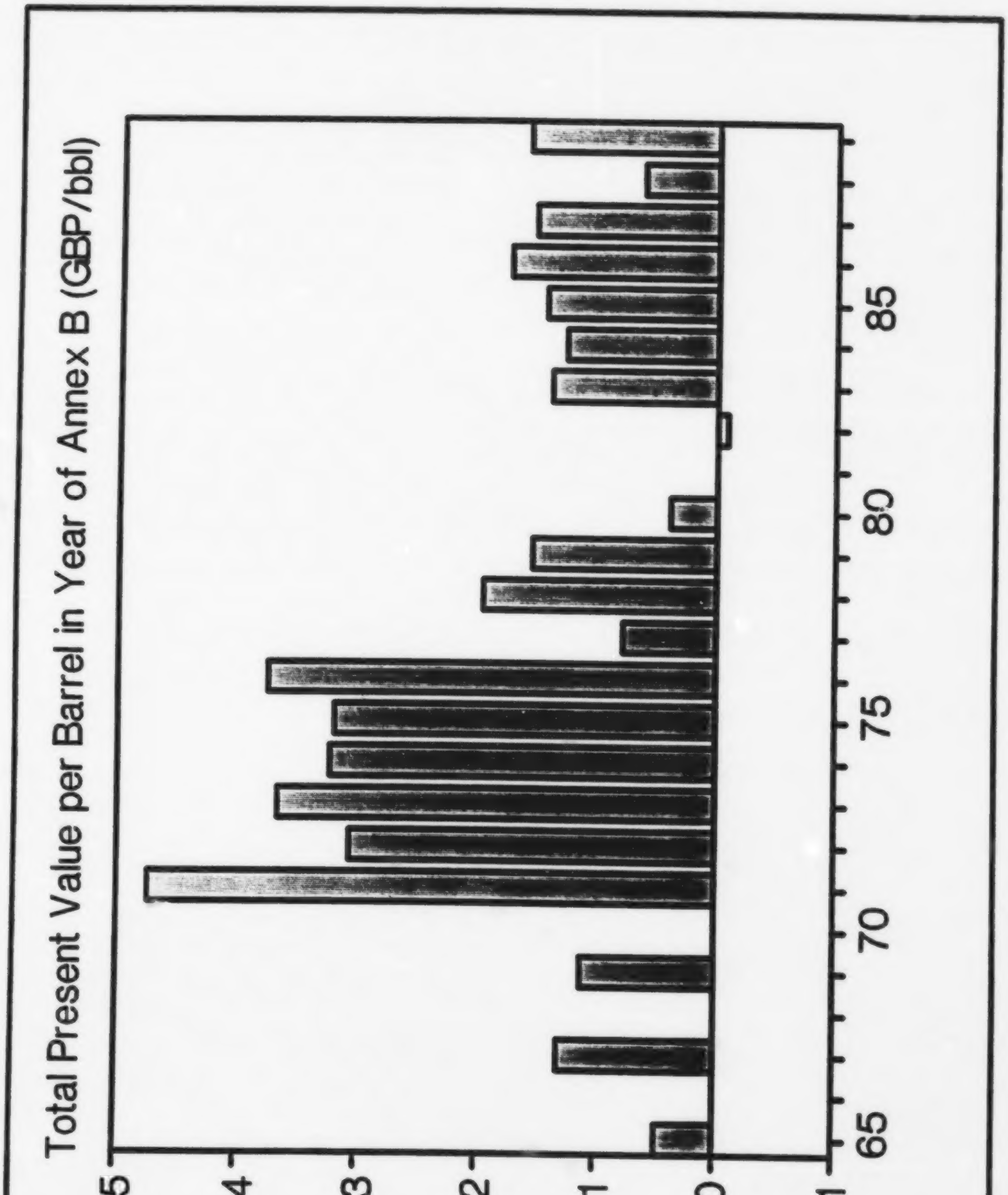

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Chart 18

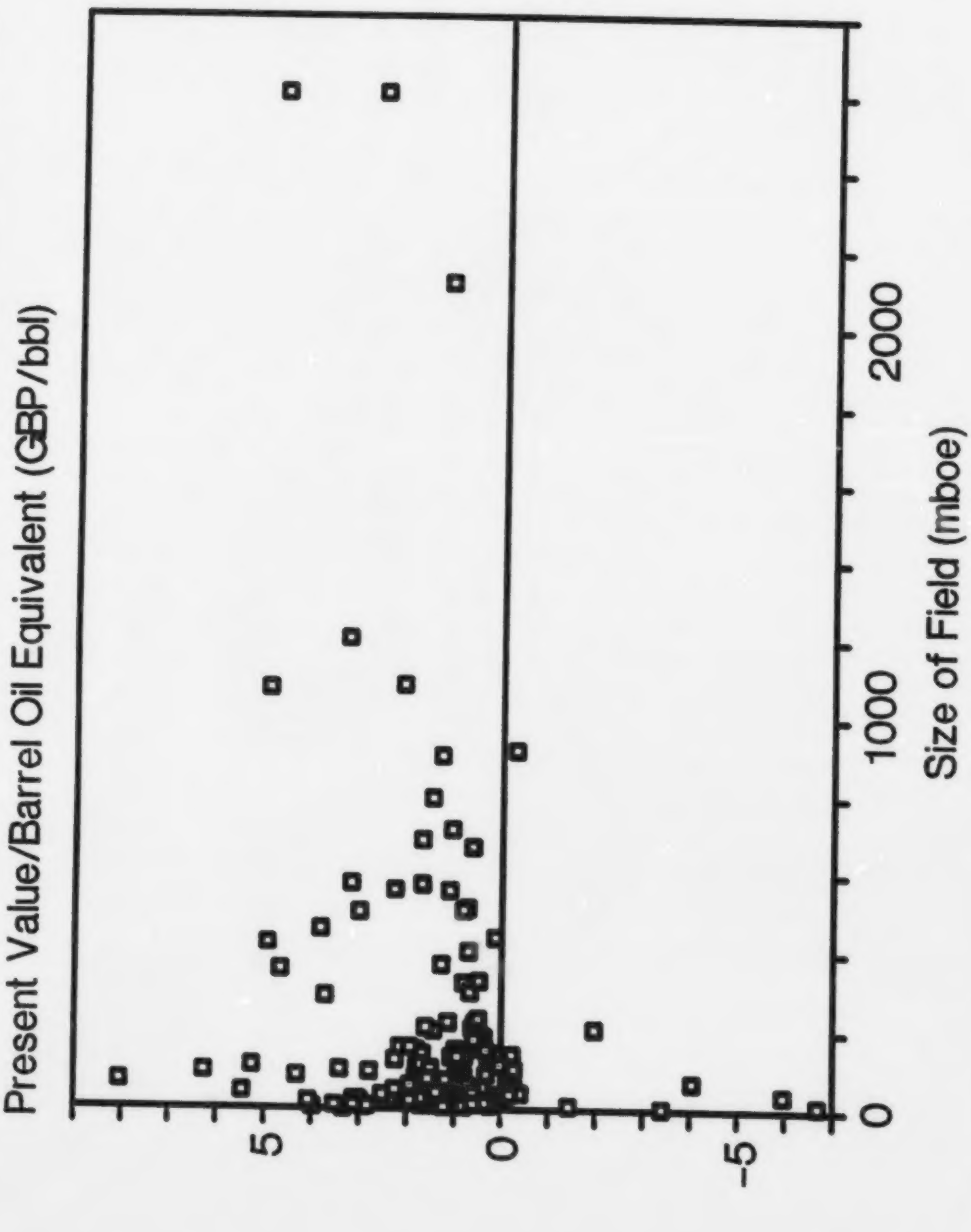

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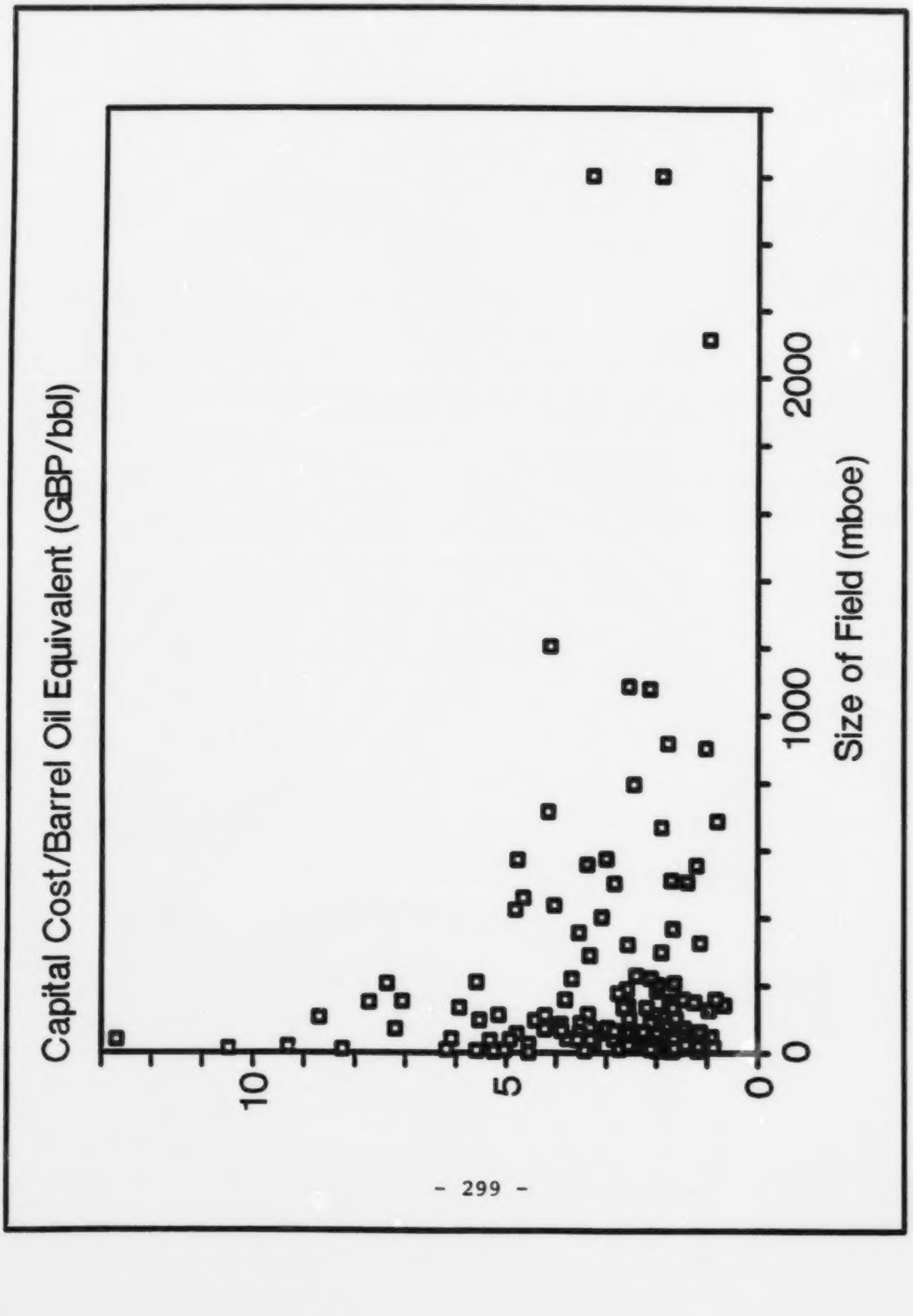
Chart 19



COUNTYNATWEST WOODMAC

CLOSING LUNCHEON ADDRESS

by

JOHN MACDOUGALL, M.P.

TIMISKAMING & PARLIAMENTARY SECRETARY

TO THE

HONOURABLE JAKE EPP

MINISTER OF ENERGY, MINES AND RESOURCES CANADA

1. Introduction

I am delighted to be in Newfoundland to speak at this conference. I am pleased that you are looking ahead to the development of frontier resources in the 1990s.

You have identified three crucial issues for future developments: world energy trends, the environment and cost-effective production. Each of these will have a major impact on development of our frontier resources. Your concern about the years ahead is shared throughout the Canadian petroleum industry. I spoke recently at the bi-annual meeting of the Frontier Division of the Canadian Petroleum Association. The Association, too, is looking ahead and considering what needs to be done to develop frontier resources.

This is a welcome sign after the mood of retrenchment of the 1980s. It suggests that Canada's frontier resources can be developed, even in the face of forecasts of modest oil price increases.

Our Government shares this belief in the potential of Canada's frontier resources, and I welcome this opportunity to speak to you about the challenges of the years ahead.

2. Hibernia Negotiations

But before talking about those future challenges, I want to say a few words about the present and where we stand on the Hibernia negotiations.

When Jake Epp spoke to you last year the Hibernia Consortium had proposed a number of design changes. The changes significantly reduced the cost of the topside structure and have made Hibernia a more viable project. The federal and provincial governments were pleased that the Consortium was making a major and significant effort to make development of Hibernia more cost-effective. But while we welcomed the changes, we were both concerned about the impact of the changes on the benefits package we negotiated in July 1988.

Accordingly, we have spent the winter in tough negotiations to ensure that offshore development brings the benefits to Newfoundlanders and to all Canadians. There is no misunderstanding about our seriousness in getting a fair level of benefits from Hibernia. In our negotiations the Consortium has demonstrated that it is prepared to be flexible in its position.

I would like to be able to tell you what the final package will look like. But there are still some details to be worked out. I can tell you that we in the federal government, the provincial government and the Consortium are optimistic that there will be an agreement soon.

3. Energy Policy Framework

No great enterprise like the development of Canada's offshore resources can be undertaken without a firm foundation.

Our government has been building this firm base for the future since 1984, when we took office and started to reverse the unfortunate direction Canada's energy policy had taken during the previous ten years. This meant moving away from heavy-handed intervention and regulation by government, from excessive taxation systems which were insensitive to profitability and from federal-provincial and regional discord. In our five-and-a-half years in office, we have implemented an energy policy built on the foundation of basic market principles -- economic efficiency, competitive prices and open markets -- to the benefit of all energy players -- industry, consumers and governments alike. Our premise has been that the competitive market must be the principal determinant of private decisions regarding energy supply, demand, price and trade if Canadians are to reap the full benefits of its significant resource endowment.

Our energy policy goals have not changed. To foster economic growth and to increase the flexibility and diversity of the Canadian energy system, the government has moved to deregulate oil and gas prices, removed discriminatory taxes on the production and exports of crude oil and natural gas, eliminated controls on short-term crude oil exports and substantially deregulated natural gas and electricity exports.

We have carried on with this approach for the development of offshore resources. Our view has always been that these resources should be managed in a spirit of cooperation rather than in an atmosphere of confrontation. The Atlantic Accord gives the people of Newfoundland a voice in the decisions that will affect their lives. We now have the stability needed to look beyond Hibernia, to the 1990s, to Terra Nova, Hebron and White Rose and to the other fields which wait to be discovered.

4. Environmental Issues

Recently, there has been a great deal of discussion not only in Canada but worldwide, about the role of energy in our society and its implications for the environment. This debate has touched on many issues, but for the oil and gas industry, two concerns are paramount. These are:

i) how oil and gas (and other fossil fuels) are consumed in the context of CO_2 emissions, the greenhouse effect and global climate change; and

ii) how oil and gas are produced in terms of the increased awareness and concerns about oil spills and offshore safety issues.

On the consumption side, as the international community moves progressively towards the adoption of targets on various forms of energy-related emissions, there is no question that our society will need to pursue:

- greater efficiency in energy use;
- the development of technologies to reduce the environmental impacts of energy use; and
- the development of alternative fuels for the future.

The government fully supports these objectives and, in particular, the adoption of measures which make both economic and environmental sense. Having said that, however, we must also recognize that oil and gas will continue to be a central part of the Canadian energy mix for the forseeable future. Frontier areas such as the Newfoundland offshore are the future of Canada's oil and gas industry, a crucial part of the ongoing diversification of Canada's energy supply. I sense a growing and broadening consensus favouring development of Canada's offshore from the residents of the areas directly affected by these developments, from those concerned about Canada's energy supply, and from the petroleum industry. To maintain and nurture this consensus, we must jointly approach development with a firm commitment to respect environment.

From a production standpoint, the significance of environmental factors is nothing new to this audience. You design your projects and products to ensure that they can withstand the environmental conditions in which they must operate. As you well know for projects in the Newfoundland offshore, that is a major challenge. But not only must we be assured that the projects can operate safely in a difficult environment, we must also be confident that our projects will not adversely affect the environment.

It is this concern which has been the focus of an increasing public scrutiny of natural resource industries. The recent experience of the Exxon Valdez incident has clearly demonstrated that one serious error by anyone of us can undermine years of environmental vigilance by us all. We each must do our part, then, to ensure that such errors are avoided. It falls to industry to ensure that training, safety and environmental standards are vigilantly pursued. It falls to governments and the regulators to ensure that the rules which you must follow are clear. It is important that all of us -- industry, regulators and government -- ensure that our actions meet the environmental expectations of Canadians.

This Government continues to believe that access to secure and competitively-priced energy is vital to our economic growth and employment opportunities. The issue which is of very real concern is how to achieve the right balance between economic and environmental considerations. No energy source is risk-free. Solutions will have costs, both personal and financial. There will have to be tradeoffs. We must ensure that when these inevitable tradeoffs are made, they reflect a full understanding of environmental considerations. I believe that the way to achieve the right balance between economic and environmental objectives is through policy frameworks that use economic incentives and economic growth as vehicles for attaining environmental objectives.

In pursuing our environmental priorities, we will have to acknowledge that there are not always simple solutions, and usually no single solution, that will achieve the required balance between our economic and environmental objectives.

Recent court decisions reinforce the fact that environmental factors must be a central part of the planning for any project. The courts have made it clear that it is a federal responsibility to consider these factors in all areas of federal jurisdiction. The courts have also made it clear that the Environmental Assessment and Review Process Guidelines Order is binding on the federal government. That means our direct responsibility for environmental assessment is much broader than previously understood.

We recognize that the court decisions have created some uncertainty for project proponents. We will respond to many of their questions in the Canadian Environmental Assessment Act, which will soon be tabled in the House of Commons. I can tell you that the federal government cannot and will not adopt a hands-off approach to environmental issues. The environment is a priority in all federal government activities and the Government of Canada is committed to the difficult task of taking a responsible approach to assuring environmental quality. Our commitment is to lead, but to lead in cooperation and partnership with our industrial sectors and citizens.

We are already taking the first steps. The Department of the Environment has begun a major public discussion on environmental issues. This public consultation will contribute to the government's environmental action plan, called the Green Plan, which will be released later this year. Given your experience, the petroleum industry and its suppliers could make a unique contribution to this process. For who better understands the three-dimensional problem of energy, the environment and the economy? I urge you to take part, if you have not already done so, in the workshops being held in provincial and territorial capitals until June 30.

5. Cost Competitiveness

There is tremendous potential in your conference's third theme -- cost-effective production. Not only could it improve the economics of frontier developments, it equally has the potential of finding ways to address the environmental challenges facing the industry. You are not strangers to cost-effectiveness.

The petroleum industry and its suppliers have shown their resilience over the last several years in adapting to a low price environment. You have had to cut costs to improve balance sheets and sharpen competitive edges. You have had to turn your attention to finding innovative ways to capitalize on opportunities. This work will continue throughout the 1990s. The opportunities before you have only been hinted at with the innovative approach to the topsides redesign for Hibernia. Today we can only speculate on the diversity of options which you may uncover in confronting the dual challenges of cost-effectiveness and environmental responsibility. For this is your real challenge, to find innovative ways to develop the wealth of our resources in an environmentally responsible way, and bring the economic promise of the Newfoundland petroleum era to reality.

Governments, too, are helping in this task. In 1985, for example, we established the Canada-Newfoundland Offshore Development Fund to spur research and development, and help Newfoundland reap the economic benefits of offshore development. Training, research and development are necessary parts of the innovations that will make a new era for Newfoundland a reality. The $300 million cost-shared fund is helping to develop world-class facilities and expertise in Newfoundland. This afternoon I will be joining Dr. Gibbons at the opening of the National Research Council's state-of-the-art offshore engineering basin at the Institute for Marine Dynamics. This project received partial funding from the Development Fund.

Together, we have the framework for development of Newfoundland's offshore resources. We must build on that framework with a commitment to the environment and an awareness of the need for innovation and cost-effectiveness. The challenges ahead can be met, and these resources can be developed for the benefit of Newfoundlanders and all Canadians.

Thank you.

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